

**Third Annual
Clean Coal Technology Conference**

Technical Papers

OBJECTIVE

THEME: "THE INVESTMENT PAYS OFF"

The public/private investment in Clean Coal Technology pays off. The objective of this conference is to review the status and successes of the program, the role of the program in meeting domestic and global energy and environmental needs, the opportunities for commercialization in the United States and abroad, and the challenges which are being encountered. This review will be accomplished within the context of the emerging trade agreements and global energy, economic, and environmental challenges.

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TECHNICAL SESSION 3:

**ADVANCED ELECTRIC
POWER GENERATION
SYSTEMS (IGCC)**

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COMBUSTION ENGINEERING IGCC REPOWERING PROJECT

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COMBUSTION ENGINEERING IGCC REPOWERING PROJECT

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ABSTRACT

This demonstration project was intended to repower an existing plant facility, the Lakeside Station in Springfield, Illinois. A single Integrated Gasification Combined Cycle (IGCC) process train was planned to generate a net output of 60 megawatts. The plant consists of a combined cycle (gas turbine, heat recovery steam generator, steam turbine) power train located in the existing buildings and a coal gasification system in a new building. The gasification system design includes ABB CE's air-blown, entrained flow, two stage gasifier, an advanced hot gas desulfurization system by General Electric Environmental Services, Inc. and the necessary auxiliary systems. The plant is designed to produce a nominal 60 MW net output with an ambient air temperature of 95oF and a cooling water temperature of 89oF on either natural gas or Illinois No. 5 coal. After the completion of plant start up and commissioning, the project was to begin a five year demonstration period to establish the operability and commercial viability of this technology. The Project has completed Budget Period 2 including the preliminary plant design and cost estimate for the installation, start-up and commissioning of this facility. The plant cost estimate proved greater than the project funding due to the complexity of the existing Lakeside Station infrastructure and scope additions and changes to the original plant cost estimate. As a result, the project will not continue at this site.

1.0 BACKGROUND

Combustion Engineering, Inc. has been involved in developing a coal gasification process to produce clean fuel gas from coal for power generation for over two decades. ABB CE has placed emphasis on developing a process for electric power generation by selecting an air blown, entrained-flow gasifier which is amenable to large scale power stations.

In the early 1970's, under joint sponsorship of the U.S. Government and Consolidated Edison Company of New York, ABB CE evaluated various types of gasification schemes for electric power generation on terms of economic, technological and environmental considerations. The study recommended that a two-stage, entrained flow, low-Btu, slagging bottom gasification process be developed for utility power generation applications.

In 1974, ABB CE initiated a program under the joint sponsorship of the United States Energy Research and Development Administration (predecessor of the Department of Energy), the Electric Power Research Institute (EPRI) and ABB CE to develop a two-stage, atmospheric pressure, entrained-flow coal gasification system.

The process was developed in a Process Development Unit (PDU) located in Windsor, Ct. The unit gasified Pittsburgh seam coal at a nominal firing rate of 120 tons per day (TPD). The gas making operation at the PDU began in June 1978 and continued over a period of three years. The objectives of the program were to produce clean, low-Btu gas from coal and to provide the design information for scale-up to commercial-size plants.

ABB CE's continued development of its gasification technology led to the introduction of a pressurized version of its two stage gasifier. In the early 1980's, the design for a 2-TPD pressurized pilot plant was developed. This pilot plant was built in 1983 and ran until 1985. A second 2-TPD pilot with design improvements was built in 1985 and operated successfully.

In 1990, ABB CE began participation in the coal gasification combined cycle repowering project that would provide a nominal 60 MW of electricity to City Water, Light & Power in Springfield, Illinois.

2.0 DESIGN

This section describes the current design for this project. There were several major plant performance requirements which impacted the design. Plant output of 60 MW net had to be

achieved at 95oF ambient temperature on both coal gas and natural gas. The gasifier had to accommodate gas turbine loads from 30 to 100 percent. Additionally, the ambient temperature design range extended from 0 to 95oF.

Plant Layout

The power island is designed to be housed in the refurbished Lakeside Station. The power island layout includes plans for a future 60 MW power train. Plant costs include the refurbishment and facilities for this future parallel power train. The gasification plant is in a separate building from the combined cycle equipment due to the lack of room in the existing building. A conceptual layout for the gasifier and auxiliaries is attached in Figure 1. The railroad line into the plant will

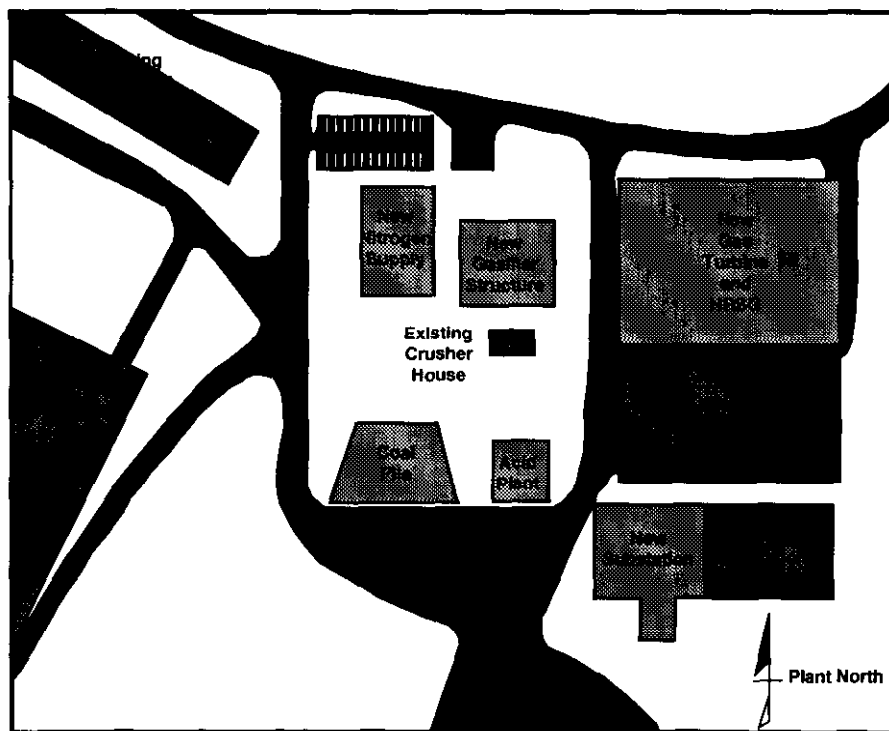


Figure 1. ABB C-E IGCC Flow Diagram

be refurbished to allow heavy components to be transported into the site. After construction, the line will be removed to allow continued operation of the coal yard. The roads through the site must remain open during construction so that coal trucks delivering to the adjacent power facility are not obstructed.

A flow diagram of the design is shown in Figure 2. A layout of the gasification equipment is shown in Figure 3 and is described below.

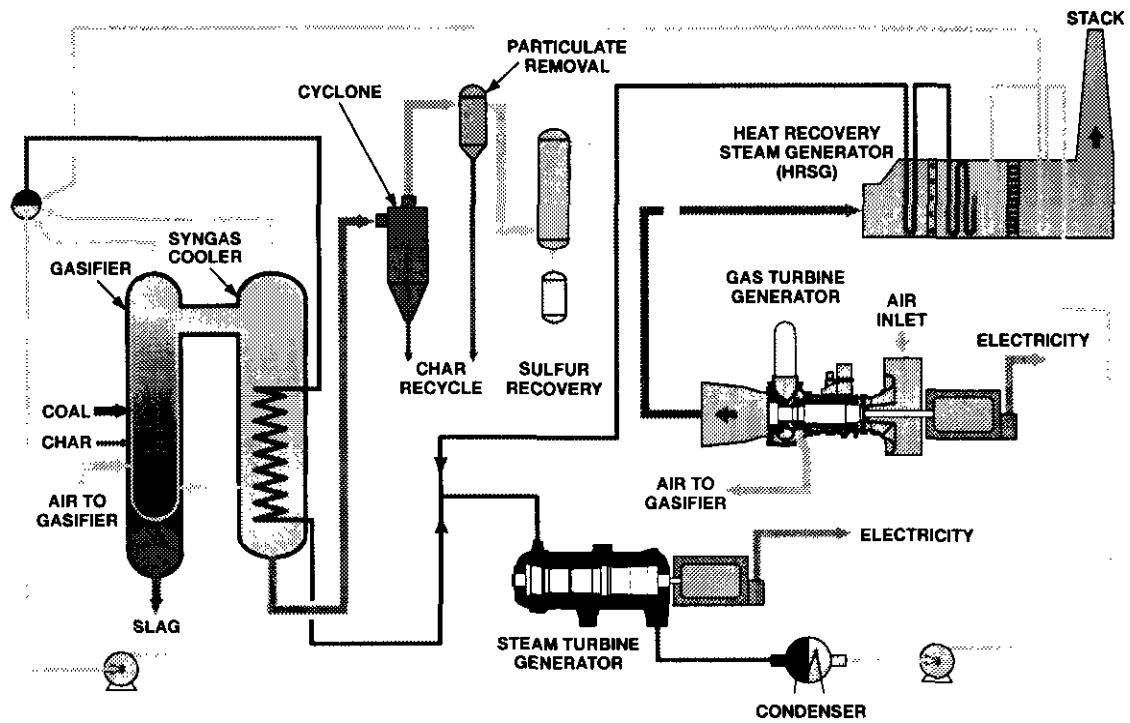


Figure 2. ABB C-E IGCC Flow Diagram

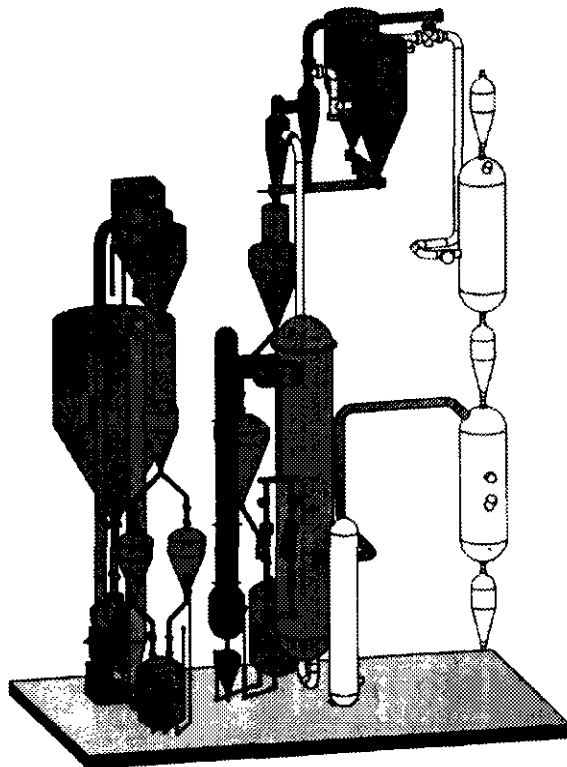


Figure 3. City of Springfield IGCC Repowering Project

Coal Storage System

Illinois No.5 coal is washed at the mine and delivered to the site in trucks. The trucks dump into open-top drive-over hoppers, with coal dropping into the receiving hopper. From the receiving hoppers, coal is transported by conveyor to the enlarged storage pile. This storage pile serves both the IGCC project and the existing Lakeside units. A new reclamation hopper beneath the coal pile reclaims coal from the storage pile and conveys it on a conveyor to the gasifier building. The reclaim hopper receives material by gravity after it has passed through a grizzly and a dust tight coal valve. The coal is transferred to the raw coal storage silo in the gasifier building. The coal handling system for the existing Lakeside units remains unchanged and will be available throughout the construction period.

IGCC Coal Preparation and Feed System

The raw coal storage silo will store enough coal for the operation of the gasifier for 24 hours. The silo will feed the coal through a slide gate shut off valve and connecting pipe to the coal feeder. The raw coal storage silo is sized to hold 600 tons of coal.

The raw coal feeder regulates the flow of coal to the pulverizing mill. It is a volumetric feeder at the outlet of the raw coal storage bin. The coal pulverizer mill grinds the coal to a fineness that can be transported pneumatically and combusted in the gasifier. It is located below the raw coal feeder.

Pulverized coal is entrained in the air leaving the pulverizer and is transported through four individual pipes to the pulverized coal baghouse. The pulverized coal baghouse separates the transport air from the pulverized coal for storage in the coal receiving bin.

The pulverized coal continuously flows by gravity to the pulverized coal receiving bin. The receiving bin stores the pulverized coal for the intermittent feeding of the lockhoppers.

There are four pairs of coal handling valves which control the flow of pulverized coal into and out of each of the two lockhoppers. The pair of valves at the inlet of each lockhopper isolate the lockhopper from the receiving bin while the lockhopper is pressurized. The pair of valves at the outlet of the lockhopper isolate the lockhopper from the pulverized coal feed bin while the lockhoppers are depressurized and coal is flowing from the receiving bin into the lockhopper.

The gasifier has three separate levels where the pulverized coal can be injected for combustion. Each level is controlled separately. The pulverized coal flow control valves meter the flow of coal from the feed bin to the pickup Tee's and control the firing rate of each burner level in the gasifier.

Gasifier/Heat Exchanger/Steam Drum

The gasifier and syngas cooler are utilized to produce a pressurized low-btu gas (LBG) or "syngas" stream which also contains char and H₂S. Pulverized coal is delivered and combusted in a deficiency of air. Gasification occurs in an entrained reactor. Sensible energy is removed from the gas in a heat exchanger called the syngas cooler. The gas exits the system for char removal and desulfurization. Coal ash is tapped from the bottom of the gasifier as molten slag. All streams to and from the gasifier are pressurized.

Product gas leaves the gasifier and passes through a crossover and enters the syngas cooler. The bounding walls of the gasifier, crossover and syngas cooler are water cooled. The gasifier and syngas cooler are vertically oriented while the crossover is horizontal. Convective superheat surface is located in the syngas cooler. The heat transfer surface arrangement is configured to yield an outlet temperature over the operating load range which is within the limits imposed by the hot gas desulfurization system. Steam that is generated and superheated is integrated into the combined cycle.

The gasifier unit is a fusion welded, eight sided waterwalled pressure vessel. It consists of multiple stages for air, steam, coal and char introduction into the gasifier. The combustion zone is the lower section of the gasifier and the reduction zone is the upper section of the gasifier.

In the combustor, coal and recycled char are burned with almost all of the combustion air to form a hot gas to start the gasification reactions and melt the ash in the coal and char. In the oxygen deficient reductor, the rest of the coal reacts with CO₂ and water vapor to generate a synthetic gas consisting primarily of N₂, CO, H₂, water and char. The char consists of unreacted carbon, ash and trace metals from the coal. Collecting the char after it exits the gasifier and reinjecting it into the gasifier provides for complete burnout of all carbon in the fuel, thereby enhancing the efficiency of the process.

All surfaces exposed to gas from the slag floor to the outlet of the crossover are studded and covered with refractory. This includes the slag tap, waterwalls and all water cooled nozzles which penetrate into the gas pass. The product gas flows from the gasifier vessel at a temperature of approximately 2000oF, to the heat exchanger where it is cooled to approximately 1000oF before being piped to the hot gas desulfurization system.

Steam is generated in the waterwalls of the gasifier vessel and the heat exchanger and superheated in the heat exchanger. Separation of the steam and water occurs in the steam drum. The waterwalls are contained inside of the gasifier and heat exchanger pressure vessels. The superheater elements are located in the gas path of the heat exchanger. Steam leaving the superheater is piped to the turbine for the generation of electric power. The annulus area between the gas pass and the inside diameter of the pressure vessel is pressurized at a pressure slightly higher than the gas pass. This maintains a blanket of non-corrosive gases on the internal walls of the pressure vessels to prevent possible corrosion by the product gas. A water seal accommodates the differential movements and provides for a gas tight seal between the annulus area and the gas pass. It allows for pressure equalization between the annulus and the gas pass during transients. Air for combustion of the coal is taken from the gas turbine compressor section. A booster compressor raises the pressure to that needed for the gasifier burners.

Slag Handling

The high temperatures in the combustion zone of the gasifier melt the slag which flows down the refractory covered waterwalls of the gasifier to the slag tap. Molten slag drops from the gasifier slag tap into a water filled tank located at the bottom of the gasifier vessel bolted to the bottom flange connection of the gasifier vessel. An inner cylindrical and conical shroud is used to funnel the slag to the grinder. The grinder is a motor driven shear shredder located inside the slag grinder pressure vessel. An auxiliary heat exchanger maintains the slag tank water temperature. Located beneath the gasifier vessel is the slag lockhopper with the associated double valving at the inlet and outlet.

The slag and water are discharged through a pair of valves to a lockhopper. The slag and water then flow through a second set of valves into a submerged scraper conveyor for dewatering and transport to the load out belt conveyor. The load out belt conveyor carries the slag to a three sided concrete ash storage bin. Ash will be loaded from the bin into trucks by a front end loader for disposal offsite.

The water processing portion of this system consists of collecting and recycling as much of the slag quench and the slag lockhopper water as possible. This recycling will reduce the load on the industrial wastewater treatment facility and minimize the makeup water requirements. The water is sent to a new concrete lined settling basin located just outside the gasifier building.

Char Removal and Recycle

Product gas leaves the heat exchanger and flows through the char cyclone and then to the char removal bagfilters. The char removed in the cyclone flows by gravity via the char seal bin to the char receiving bin. Char collected in the bagfilters discharges by gravity to the char receiving bin. The baghouse is cleaned by pulsing the bags with low pressure steam. The filtered product gas is piped to the hot gas desulfurization system. The char cyclone and char removal bagfilters operate at approximately 1000oF and 300 psi. The bagfilter is designed to use Nextel ceramic bags at present. Sintered metal and ceramic crossflow filters are also being considered.

The char is collected in the char receiving bin and feeds out intermittently to two char lockhoppers. The flow is controlled into and out of each lockhopper by pairs of char sealing valves. The char lockhoppers are pressurized with steam to a pressure higher than the operating pressure of the gasifier and intermittently discharge to the char feed bin by gravity. During start up and shut down, the lockhoppers and feed bin are pressurized using nitrogen. Inside of each lockhopper, receiving bin and feed bin, there are fluidizing devices to keep the char from compacting and keep the char flowing from vessel to vessel.

The char feed bin continuously feeds char through the flow control valves at a pressure high enough to overcome the gasifier operating pressure. Char is fed through either of the two flow control valves to char pickup Tee's. When the unit is operating, transport steam is introduced to carry the char to stream splitters where the char flow is divided and piped to the char burners. During start up, nitrogen is the transport medium. The char is reinjected into the gasifier at either or both char burner levels to finish volatilization of the char particles. There will be no waste stream other than slag during normal operation.

Hot Gas Desulfurization System

The syngas leaving the char removal baghouse has been cleaned of particulate matter. The syngas is expected to consist primarily of N₂, CO, H₂ and water with low concentrations of H₂S, COS, CS₂ and chlorides. The sulfur and chlorine compounds must be removed prior to combustion of the syngas in the gas turbine. To maintain the overall thermal cycle efficiency, the gas is not cooled before entering the gas desulfurization system. The syngas enters the absorber and flows countercurrent to a moving bed of zinc titanate (ZnTi) pellets. The absorber is a high pressure and temperature vessel filled with zinc titanate sorbent material. The gas enters the side of the absorber in the lower section and flows upward causing the gas to come in direct contact

with the zinc titanate and the sulfur in the gas combines with the sorbent. The sulfur compounds (mainly H₂S, COS and CS₂) in the gas will react with the sorbent.

Following sulfur adsorption, sorbent material is conveyed to a lockhopper and then to regeneration. In the regenerator, the metal oxide is regenerated and SO₂ produced. Regenerated sorbent, purged of SO₂ is recycled to the absorber lockhopper. The supply of regenerated metal oxide is slightly depleted during regeneration and handling. Fine particles of sorbent entrained in the cleaned gas stream are captured in a downstream high efficiency cyclone. The ZnTi fines, because of their high zinc content, are recycled to the sorbent supplier and will not be a waste byproduct.

Chlorides are removed from the gas upstream of the absorber. Nahcolite is injected into the syngas after the char removal baghouse. The Nahcolite converts the chlorine into NaCl which is a solid and can be filtered out and disposed of offsite. Heat generated in the regeneration process will be used to generate steam which is piped back to the gasifier steam drum. The clean syngas is piped to the gas turbine for combustion. The SO₂ produced during sorbent regeneration is piped to the sulfuric acid production plant.

When a set pressure drop has been reached in the absorber on the gas side, a portion of the absorber bin's inventory is discharged through a lockhopper to the sorbent regenerator. At atmospheric pressure and under controlled solids flow rates, temperatures, air quantities and locations, the sorbent is regenerated by oxidation, producing an SO₂-rich gas which is cooled and sent to an acid plant for conversion to sulfuric acid. With the regeneration of sorbent completed, the sorbent is discharged from the bottom of the regenerator, screened and sent to a bucket elevator. The elevator carries the sorbent back to the top of the absorber where it is introduced back into the absorber feed bin. In this way the freshest sorbent is in contact with the cleanest gas to get the best sulfur removal. The cleaned gas leaves the absorber and any entrained particles are removed as the gas goes through the secondary cyclone.

Sulfuric Acid Recovery System

The gas stream leaving the regenerator of the hot gas desulfurization system consists primarily of SO₂ and nitrogen. The gas stream is humidified, cooled and dried so that the moisture remaining in the gas is equivalent to the water content of the product acid. The gas is heated in a recuperative heat exchanger against exiting gases and passed through a four stage catalyst bed, which converts 99+ percent of the SO₂ to sulfur trioxide (SO₃). The bed will be periodically cleaned and replaced as necessary. The mixture is further cooled in another recuperative heat

exchanger and passed through either one or two contact absorption towers, where the SO₃ is absorbed into 98 percent H₂SO₄. The acid is then transferred to an acid storage tank. The acid is of commercial grade quality and represents a marketable byproduct rather than a waste stream. The sulfuric acid production plant is free standing and separate from the gasifier building or from the Lakeside Station building.

Combined Cycle

After particulate and sulfur removal, the syngas is fired in the combustion turbine. The turbine is a GE Frame 6 model. The turbine will have the capability to be fired with natural gas if the gasifier is out of service. The gas turbine is located in the renovated Lakeside Station building. The exhaust from the gas turbine is approximately 1030oF at full load. This exhaust gas is routed to the heat recovery steam generator. The air for the combustion of the coal and char in the gasifier is extracted from the compressor section of the gas turbine. A booster compressor controls the amount of air extracted and further increases the pressure of the combustion air. The air is cooled after extraction from the gas turbine. Heat is captured in a heat exchanger and is used to generate steam for the steam turbine cycle.

The heat recovery steam generator (HRSG) takes the hot exhaust gas from the gas turbine and recovers the heat to generate steam. The HRSG is able to fire natural gas to supplement the gas turbine output during high ambient temperature conditions and when the gasifier is off line and the gas turbine is firing natural gas only. The HRSG is located in the Lakeside Station building. The exhaust gas leaving the HRSG is ducted up and over the roof to a new stack. The HRSG will be delivered in preassembled modules with final assembly being performed in the field. The inlet ducting is a prefabricated and pre-insulated construction.

Steam from the HRSG plus steam from the waterwalls of the gasifier and various gasifier heat exchangers is piped to the steam turbine. The steam turbine will operate with steam at 1265 psia and 950oF at the throttle inlet valve. The steam turbine is connected to a synchronous generator that will produce 37 megawatts. The steam is exhausted from the turbine down into the steam condenser. The condenser cools the steam back to condensate and returns the water back into the cycle. The cooling water for the main condenser comes from the lake water circulation system.

Circulation water will be taken from the intake tunnel by two motor driven pumps. A flow of 50,400 gpm will be sent to the surface condenser. The remaining flow will be diverted to the slag water makeup pond and the closed loop cooling system.

3.0 OPERATIONS AND MAINTENANCE

The operations and maintenance budget was developed with input from the personnel of Duke Engineering & Services, Duke/Fluor Daniel Operations, ABB CE and CWL&P Operations. Plant layout, equipment specifications, vendor quotations, process descriptions, P&ID's, PFD's and the Project Design Questionnaire were reviewed and the basis for the budget was established.

The costs reflect a 60-month operating period commencing with start up of commercial operation and including certain costs that would be incurred during the commissioning period. Unit costs for fuel and utilities were specified by CWL&P.

Operations personnel would begin their involvement up to 20 months preceding the commercial operations date. Union labor rates and fringe benefits reflect those currently in effect at CWL&P, with escalation applied to the years of incurred cost. Mobilization of operations personnel was planned to begin 20 months prior to commercial operations and full staffing reached 4 months before commercial operation. For estimating purposes, the project staffing level (67 people) is considered a "stand alone" facility. Costs for plant support services (human resource functions, accounting, procurement, etc.) have been included.

Plant capacity factors utilized during each year of operation coincide with the BACT document: Year 1 - 30% (2,630 hrs/yr), Year 2 - 50% (4,383 hrs/yr), Year 3,4,5 - 80% (7,013 hrs/yr). Natural gas was utilized for turbine peaking operation, limited at 1000 hours per year per the BACT assessment.

Ash (slag) disposal would be in the existing CWL&P ash pond. Estimates for offsite disposal have been identified. Electrical auxiliary power usage, while quantities have been established, have not been included in the O&M cost estimate. Existing CWL&P wastewater treatment facilities will be utilized.

4.0 COST ESTIMATE

In arriving at the cost estimate for this project the combined technical and commercial expertise from both Duke Engineering and Services and ABB CE were utilized.

Engineering selections and drawings were produced for all major components, systems and sub-systems to facilitate optimum price development both internally and externally.

Firm price quotations were requested from a minimum of three vendors for each major piece of equipment which make up the entire plant scope. These quotations were reviewed by ABB CE and DE&S for technical and commercial completeness.

Takeoffs from contract quality drawings were made to quantify interstage piping, instrumentation, valving, power and control wiring, conduit, platforms, walkways, building siding, support structures, concrete work, insulation and lagging.

Heavy structural steel fabricators were involved in the pricing of the major components of the gasification plant (e.g. gasifier, heat exchanger pressure vessels, steam drum, coal and char receiving bins/lockhoppers, steam turbine, heat recovery steam generator, etc.) to ensure current labor and material costs, and that optimum designs were reflected in the pricing.

Vendor and in-house cost databases were examined with respect to determining pricing relevance to similar designs/materials selection criteria.

Construction Labor costs to dismantle existing equipment and erect the new systems/components were based on single shift straight time, 40 hour week and local union labor composite costs. The optimum nature of the total construction price reflects the merging of the quality of the ABB CE discrete design and drawing data to the construction and O&M estimating expertise of Duke Engineering and Services. Facilitating the completeness and accuracy of the total construction price was the rather comprehensive analysis of the local site labor conditions.

5.0 STATUS

The preliminary design and cost estimate of the ABB CE IGCC Repowering Project has been completed. The preliminary design demonstrates that the air-blown, pressurized, entrained flow gasification process is viable for power generation applications.

The cost estimate is for an entire stand alone plant with the added complexity of renovating the existing building and maintaining the existing coal fired boilers on-line. The costs were higher than originally expected but the scope of work and the complexity of construction also exceeded the original expectations.

However, CWL&P's near term needs call for peaking power rather than baseload power provided by the IGCC system. For this reason coupled with site related constraints and associated cost estimates which were higher than anticipated, the project will not continue at this site.

The cost should not be construed as the final cost of an air-blown, entrained flow coal gasification system. The reasons include such factors as system capacity, site limitations, complexity of the preliminary design and first of a kind systems. The capacity, 60 MW net, is small for a utility power plant and contribute to the high cost since many fixed costs that are associated with engineering a plant would be the same for a much larger size plant. Therefore, a larger plant would yield a lower cost per kilowatt. Similarly, the fact that this project is being designed as a first of a kind plant with many systems being designed from scratch adds cost. The site requirements affected the design of the plant which in turn affected the cost. The site requirements and extended scope also added costs which are not normally considered in a commercial plant, especially with respect to those added costs for:

- Supplying and erecting the natural gas supply line into the site;
- Re-constructing the abandoned rail line(s) into the site;
- Utilizing the existing boiler building;
- Inability to use existing steam turbine;
- Incorporating a steam turbine bypass;
- Electrical transmission equipment/switchgear beyond the primary terminals of the transformer;
- Dismantling and re-arrangement costs associated with integrating the new systems/components with the existing systems/components; and
- Refurbishment and system costs for a future parallel power train.

Commercializing this technology will require that a demonstration facility be constructed. A new site needs to be found where significant portions of the plant can be reused without incurring expensive reconstruction and renovation. The customer should be planning to use the unit as a baseload unit and not as a peaking unit for part time operation. The hot gas desulfurization system and the hot particulate filter system are critical to the success of this technology and need to be developed independent of this project. Fuel and char feed systems which are more cost and space efficient need continued investigation.

PIÑON PINE POWER PROJECT - AN UPDATE

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ABSTRACT

Sierra Pacific Power Company (SPPCo) plans to build the Piñon Pine Power Project at its Tracy Power Station near Reno, Nevada. This integrated coal gasification combined cycle plant will convert approximately 800 tons of coal per day to a net electricity output of 95 MW. The project was selected by the U.S. Department of Energy (DOE) for cost shared funding under Round IV of the Clean Coal Technology Program and the Cooperative Agreement between SPPCo and DOE was executed in August 1992.

The project will demonstrate the KRW fluidized bed gasification process operating in the air blown mode as well as systems to remove sulfur and particulates from hot coal gas.

Foster Wheeler USA Corporation (FW USA) will provide engineering and construction management services. The M. W. Kellogg Company (MWK) will provide engineering of the gasifier and hot gas cleanup systems.

This paper outlines the goals of the project and provides an update on the technical and commercial aspects.

INTRODUCTION

Sierra Pacific Power Company's (SPPCo) Piñon Pine Power Project was one of nine successful proposals selected by the U.S. DOE from thirty-three submitted in response to the Program Opportunity Notice for Round 4 of the Clean Coal Technology Program. The project includes the design, engineering, procurement, construction, and testing of a nominal 800 ton per day coal fueled integrated gasification combined cycle (IGCC) plant generating a nominal 95 MW net. The facility, which will be owned and operated by SPPCo, will be built at their Tracy Station some 20 miles east of Reno, Nevada. The Tracy Station currently has a combination of gas/oil fired boilers and peaking combustion turbines which have a total capacity of 400 MW.

In this project SPPCo aims to demonstrate the use of advanced coal based technologies to produce clean and low cost power to meet their growing customer needs.

The heart of the Piñon Pine Power Project will be the KRW fluidized bed ash agglomerating coal gasifier operating in the air blown mode. Cleanup of the hot gases involves the use of a calcium based sulfur sorbent in the gasifier and an external regenerable desulfurizing sorbent which removes most of the sulfur from the produced gas. A ceramic barrier filter removes all but a trace of particulates. Since the fuel gas is cleaned at high temperature, thermal inefficiencies associated with cold gas cleanup are avoided. The cleaned coal gas is burned in a gas turbine which produces about 60 percent of the plant power output. The rest of the power is produced in a steam turbine generator operated on steam generated from gas turbine exhaust.

The project is currently scheduled to startup late in 1996 with operation on coal by the end of that year. For the execution of the project SPPCo has contracted with Foster Wheeler USA Corporation (FW USA) for the engineering, procurement, and construction management. FW USA, in turn, has subcontracted with The M. W. Kellogg Company (MWK) for engineering and other services relating to the gasifier island. Figure 1 shows the organization for the execution of the project.

PROJECT GOALS

SPPCo's primary objective for the Piñon Pine Power Project is to utilize advanced technologies to generate low cost base-load power using coal in a clean, environmentally acceptable manner. The added electricity generating capacity will help the company meet the future demand for power in Nevada which is expected to continue to grow at about 4% annually. Success in meeting these objectives will be measured against a number of criteria, including:

Environmental Acceptability

SPPCo has a corporate commitment to be environmentally responsible and has earned national recognition as a "green" utility. The Piñon Pine Power Project will produce electricity from coal with very low emission of pollutants. Sulfur and nitrogen oxides emission will be much lower than the best coal fired conventional power plant and statutory requirements. A barrier filter will reduce particulates to a very low level. The high efficiency of the IGCC system means a lower generation of carbon dioxide per MW of electricity generated as well as reduced water consumption which is of great importance in the arid climate of Nevada.

Economic Benefits

SPPCo conducts its own resource planning to meet its customer needs for electricity which is based on load growth projection, supply-side and demand-side options and consideration of other factors such as fuel mix, environmental effects and financial constraints. Calculations for the Piñon Pine Power Project show that when the cost share by the DOE is considered it is the least cost option of increasing generating capacity with the added benefits of fuel flexibility and environmental acceptance.

The project will also provide economic benefits in the state and local community through employment opportunities and an increase in the tax base.

Fuel Flexibility

The Piñon Pine Power Project has the capability to run on a wide range of coals. The design is based on low sulfur Utah bituminous coal available from a number of suppliers. During the operating and testing period tests are planned on high sulfur eastern coal. The gas turbine selected for the facility has the ability to operate on natural gas and propane as well as coal gas, enhancing availability of the unit.

The existing Tracy Station operates on natural gas and light petroleum distillate. This new project will further increase fuel flexibility and permit SPPCo to take advantage of variations in the price of different fuels to minimize the cost of electricity to its customers.

Technical Factors

The Piñon Pine Power Project is to demonstrate the KRW pressurized fluidized bed coal gasification process operating in the air blown mode to produce low heating value fuel gas to fire a gas turbine. Other key technical objectives to be demonstrated include:

- The combination of in-bed desulfurization using a limestone sorbent and external desulfurization of the hot gas by means of a regenerable zinc based sorbent to achieve sulfur removal in excess of 97% with low-sulfur western coal, and 99% when processing high sulfur eastern coal.
- The integration of the gasifier system with the combined cycle section to produce the degree of control and response to demand changes required by the power generating industry.

COST AND SCHEDULE

The federally cost shared Piñon Pine Power Project is scheduled to take 96 months to complete, including the design, engineering, construction, startup and a 42 month demonstration phase. The total project cost is approximately \$270 million shared equally between SPPCo and DOE.

As shown in the project schedule (Figure 2), SPPCo startup of the facility is planned for late 1996. Current work includes firming up design details and preparing the Phase I cost estimate. Concurrently, the required environmental permitting processes are proceeding with permission to start construction expected by February 1995.

After the demonstration period, SPPCo will continue to utilize the plant for power generation to meet its needs. The expected life of the plant is in excess of 20 years.

TECHNICAL OVERVIEW

Process Description

The two major components of the plant are the gasification island and the power island. Figure 3 is a Block Flow Diagram of the processes to be employed in the Piñon Pine Power Project. Additional services and infrastructure required by a facility of this type are also included in the project scope.

Raw coal will be received at the plant in weekly unit trains consisting of 100-ton automated bottom dumping railcars. Once unloaded, coal will be stored and transported in enclosed equipment to minimize dust emissions. The coal is received and stored as 2" x 0 and is then transferred to a preparation area where it is crushed, sized, and passed to a day-bin for feeding the gasifier island. Sized limestone and dried coke breeze (for startup) are received by covered truck and are also stored in silos close to the gasifier island.

In the gasification island, crushed and sized coal and limestone are metered through lockhoppers and fed pneumatically through a central feed tube in the bottom of the gasifier. The temperature of the bed is controlled by metering the air and steam into the gasifier's central jet. The coal/limestone bed is maintained in a fluidized state in the gasifier by the jet and use of recirculating gas. Partial combustion of char (devolatilized coal) and gas occurs within the bed to provide the heat necessary for the endothermic reactions of devolatilization, gasification, calcination and desulfurization. Spent limestone and ash (known collectively as Lash) are removed from the bottom of the bed and are further processed in the sulfator in which the calcium sulfide is converted to the sulfate form.

Coal gas leaving the gasifier passes through a cyclone to remove the majority of the particulate matter which is returned to the fluidized bed and is then cooled to 900-1100°F before entering the hot gas cleanup section. In this section of the plant the gas is cleaned by a combination of a ceramic filter medium to remove essentially all the particulate material, and regenerable sorbent to remove nearly all the remaining sulfur components. A zinc oxide based sorbent known commercially as Z-Sorb is undergoing testing for use in the desulfurizing reactors.

The loading of the Z-Sorb Sorbent and its regeneration will be effected by means of an external desulfurization system. The sorbent regeneration is carried out using an air stream which conveys the sulfur oxides released from the sorbent to the sulfator where reaction with lime and air forms calcium sulfate. This material exits the system along with the Lash in a form suitable for landfill or potentially to be used as a commercial byproduct.

In the power island the clean low Btu coal gas will be delivered to a General Electric MS6001FA combustion turbine/generator which will produce approximately 61 MW on this fuel. The combustion turbine is designed to also fire natural gas, propane or a blend of natural gas and coal gas.

The MS6001FA is a new machine offering a high firing temperature (2350°F) and a high exhaust temperature (1100-1125°F) making it very efficient in combined cycle operation.

Exhaust gas from the combustion turbine is used to generate steam in the heat recovery steam generator (HRSG). Steam generated in the HRSG and the gasifier island are combined and superheated in the HRSG. The steam cycle will be 950°F/950 psig, with the steam turbine/generator producing approximately 43 MW.

Steam is generated at one additional pressure level in the HRSG, namely, 75 psig which is utilized for deaeration and power generation. The HRSG also includes a section for condensate heating.

Plant Performance

With a 950°F/950 psig steam cycle, the Piñon Pine Power Project will be 15-20% more efficient than SPPCo's current coal-fired units. This represents a significant improvement in SPPCo's system heat rate. Using coal fuel and its demonstrated price stability relative to other fuels, the Piñon Pine Power Project will deliver least cost power generation to SPPCo's customers.

COMMERCIALIZATION

During the remainder of this decade it is expected that there will be little in the way of new coal-based power plants in the U.S. It is generally accepted, however, that the early decades of the next century will see a resurgence in the use of coal as a fuel for generating electricity. The Energy Information Administration¹ estimates coal usage for power generation will maintain its market share at about 54% through 2010. This correlates with an additional 42,000 MW of new coal-based capacity to be on line by that date. To meet this timetable, technical decisions for the new power generation capacity will be made late in this decade to allow time for constructing the new facilities.

As a result of its relatively high efficiency coupled with low emissions characteristics, the IGCC technology is expected to play an increasingly important role in the future plans for power generation. As different IGCC processes and equipment are demonstrated,

optimized, and refined, capital costs are more accurately being assessed and in general are decreasing.

The Piñon Pine Power Project offers the opportunity to demonstrate the feasibility of integrating the KRW air blown fluidized bed coal gasification process with a combined cycle, and the associated capital and operating costs. The 42 month period for operation and testing will enable the long term reliability, maintainability and environmental impact to be assessed. This schedule will enable assessment information to be available to Utilities and Independent Power Producers (IPPs) as they decide on their future capacity increases.

In the interim SPPCo and its team will be continuing its marketing work to ensure that potential customers are kept abreast of developments. The knowledge gained as we proceed with the Piñon Pine Power Project will be used to regularly update the information made available to potential users. Indeed, we will be seeking opportunities to work with Utilities and IPPs in assessing how the Piñon Pine IGCC technology can be incorporated into their future power generation capacity needs. In particular, we see considerable commercial possibilities in repowering power plants where the coal fired boiler is approaching the end of its useful life. Such a repowering which will include a combustion turbine and HRSG, or course, will yield a plant capable of far greater power generation capacity than the original boiler and steam turbine system together with improved thermal efficiency and lower emissions.

In addition to the USA, we see a market for this technology overseas with potential customers being foreign enterprises as well as U.S. IPP's investing in power generating facilities in other parts of the world. Of course, the market place is not without competition. In addition to the different IGCC technologies being demonstrated under the Clean Coal Technology Program there are competing technologies in the process of being demonstrated in other areas of the world including Europe and Japan. However, the KRW air blown fluidized bed concept together with hot gas cleanup simplifies the IGCC process as well as giving an improved efficiency - a combination that we believe will be attractive to users.

We look for a successful demonstration as the outcome of our Piñon Pine Power Project so that the technology can take its place in supplying the world's need for power in the next century. We are confident, indeed, that "The Investment Pays Off".

References

1. Energy Information Administration, Annual Energy Outlook 1994 with Prediction 1. 2010, DOE/EIA 0383 (94), January, 1994

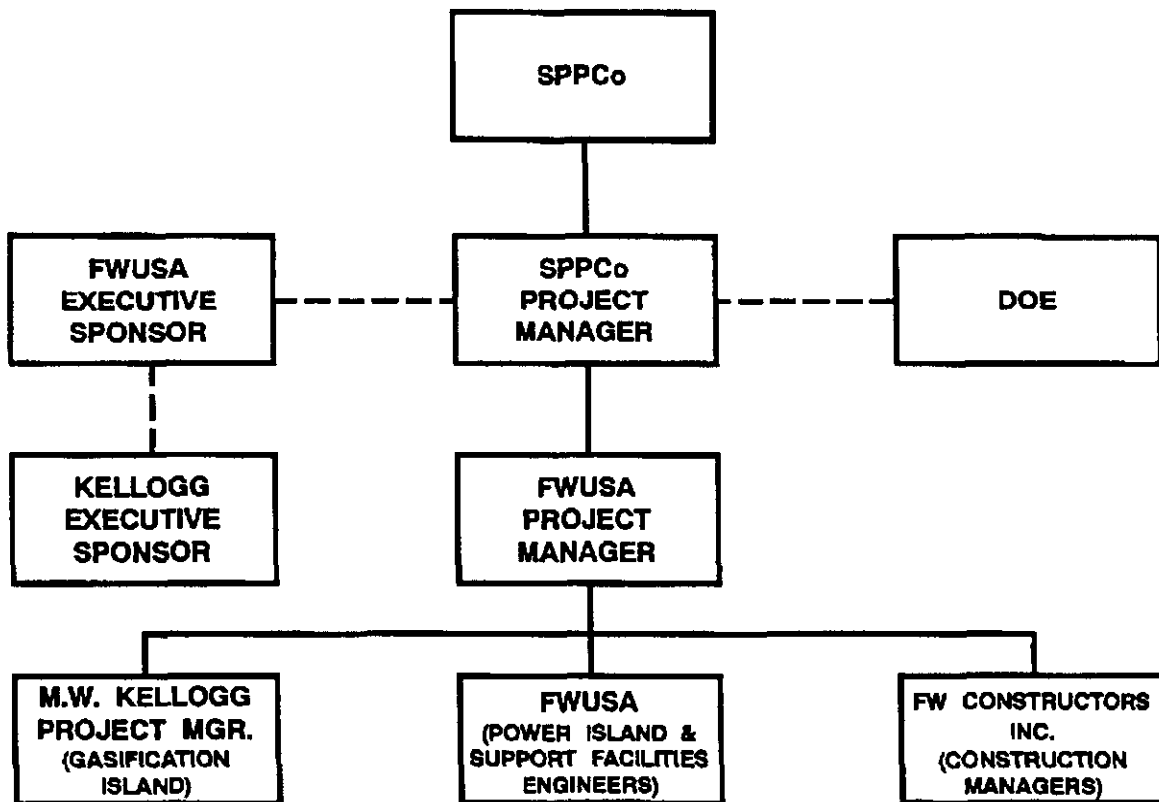


Figure 1 Project Organization

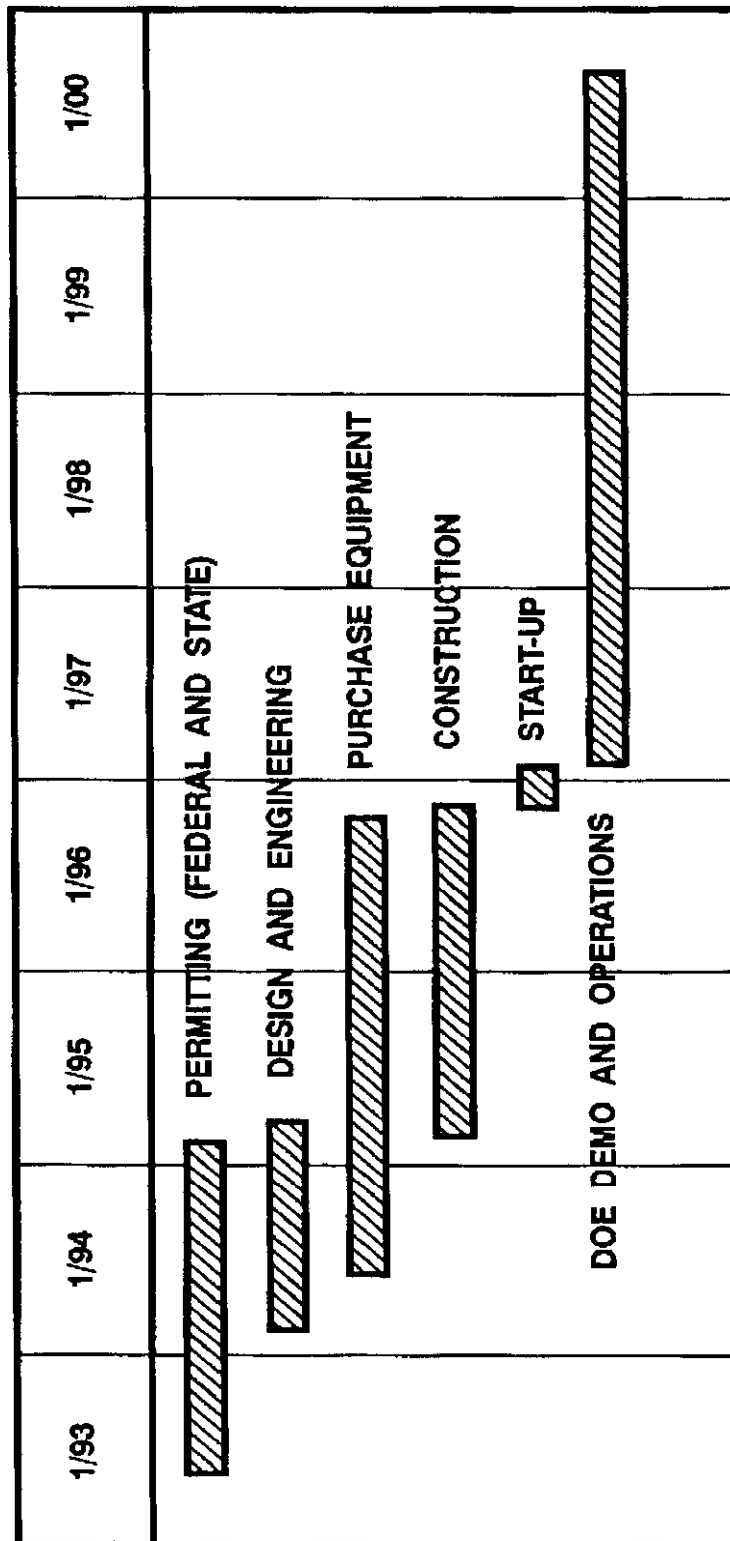


Figure 2. Schedule of Piñon project

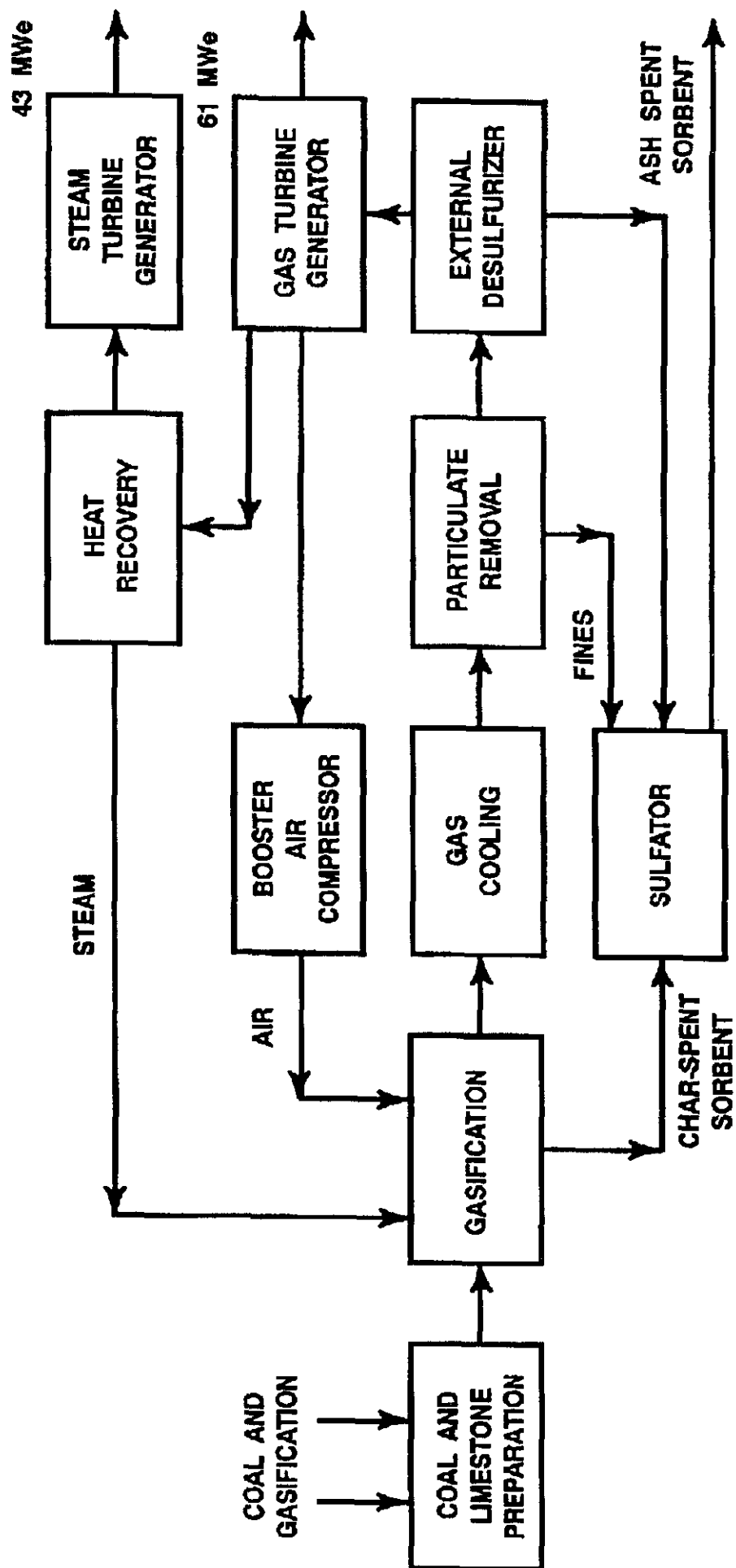


Figure 3. Block Flow Diagram

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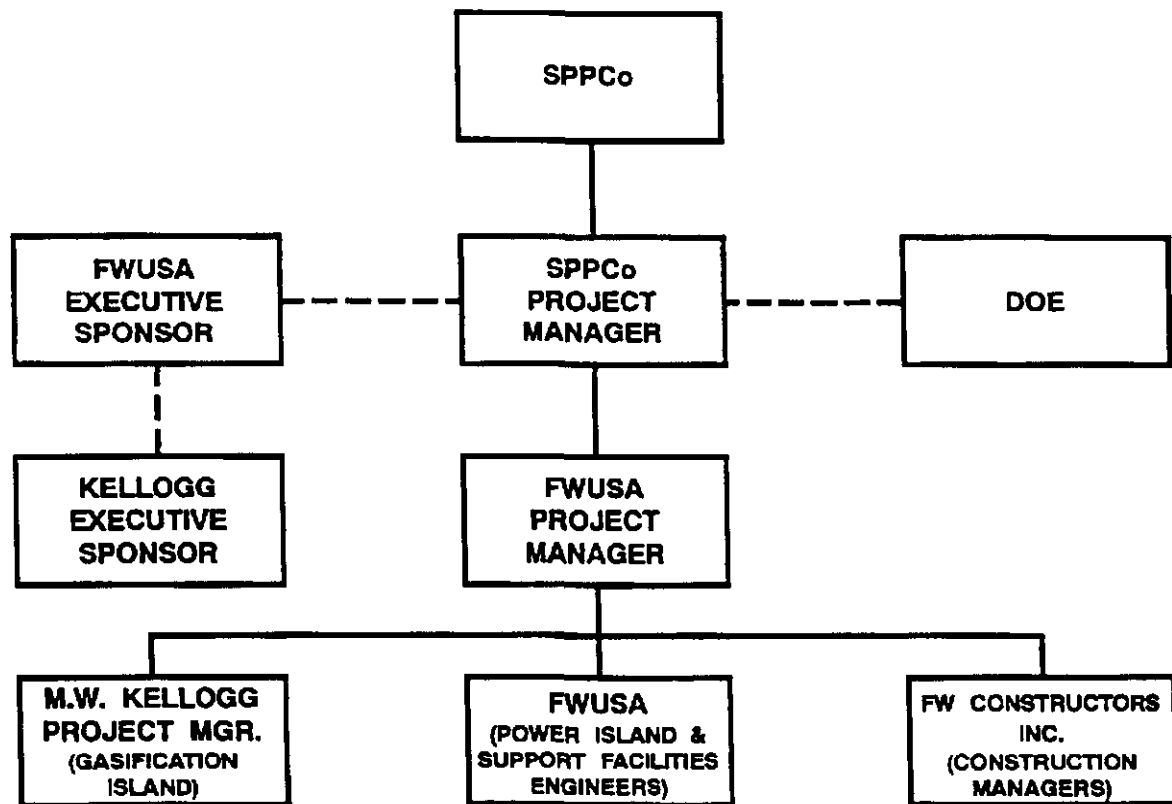


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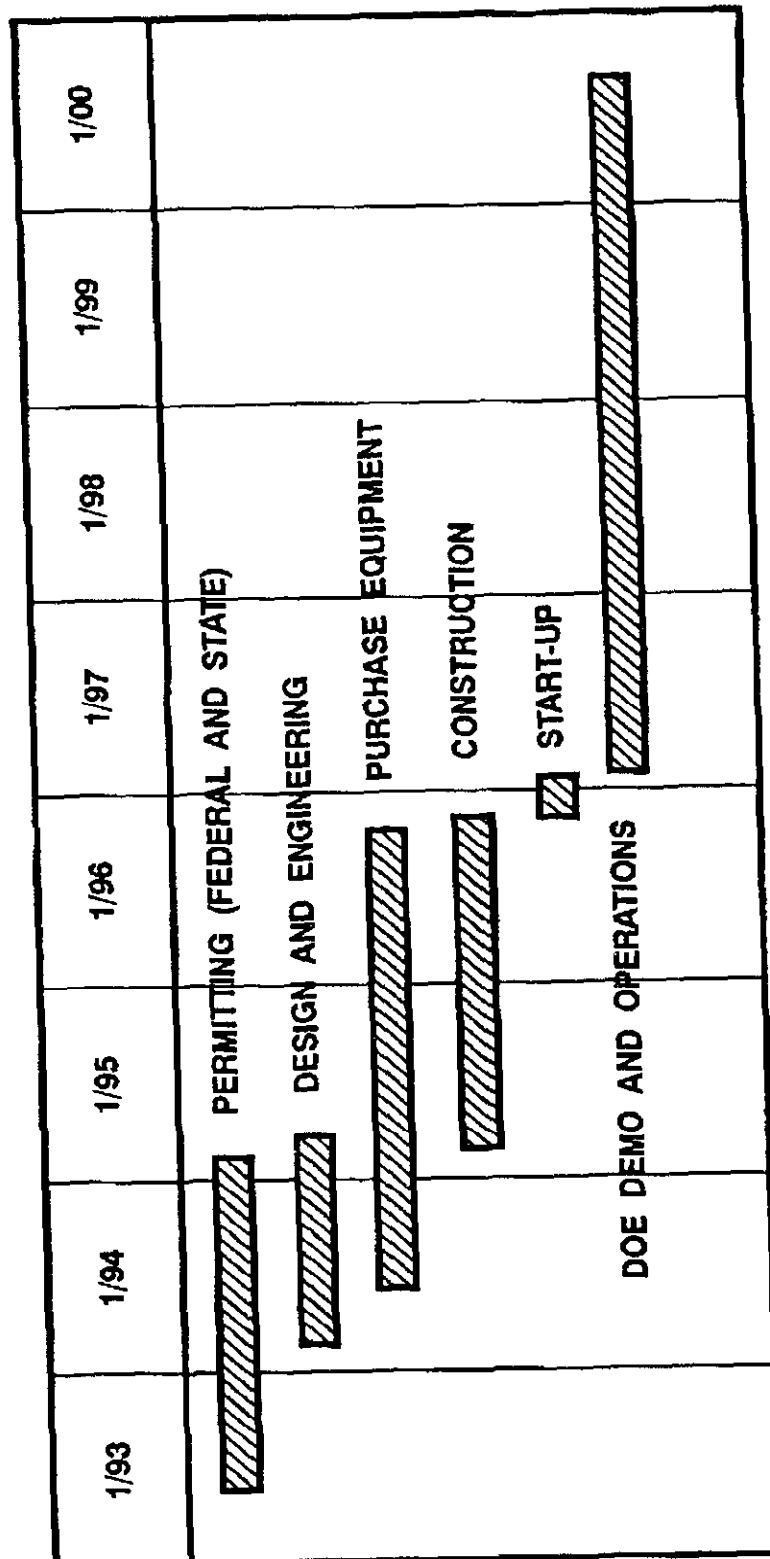


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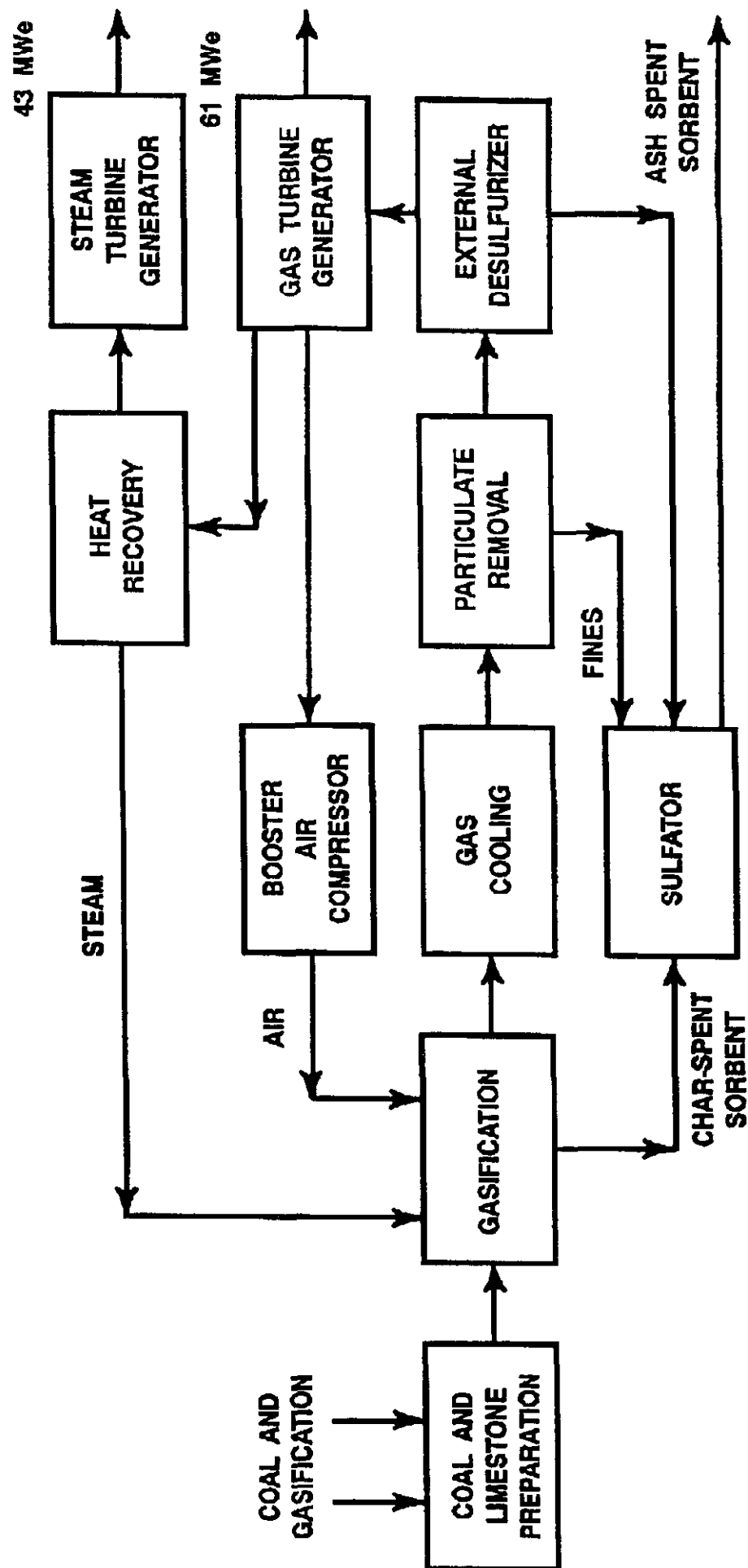


Figure 3. Block Flow Diagram

THE WABASH RIVER COAL GASIFICATION REPOWERING PROJECT AN INVESTMENT IN THE FUTURE

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ABSTRACT

The Wabash River Coal Gasification Repowering Project (the Project), conceived in October of 1990 and selected by the United States Department of Energy as a Clean Coal IV demonstration project in May 1991, is now over 70% complete after initiation of construction in July 1993. The Wabash Project is a joint venture of Destec Energy, Inc. of Houston, Texas and PSI Energy, Inc. of Plainfield, Indiana, which will repower an existing 1950's vintage coal-fired steam generating plant with coal gasification combined cycle technology. The Project is located in West Terre Haute, Indiana at PSI's existing Wabash River Generating Station and will process locally-mined Indiana high-sulfur coal to produce 262 megawatts (net) of electricity. Upon completion in 1995, the project will not only be the largest single-train coal gasification combined cycle (CGCC) power plant in operation in the United States but will also be operated in a fully commercial setting while emitting lower emissions than other high sulfur coal fired power plants and improve the heat rate of the repowered unit by approximately twenty percent. The Project demonstrates how coal gasification combined cycle technology can be used to meet domestic and global energy and environmental needs.

This paper will summarize the challenges overcome by the Project and its present status, as well as outline the future direction and challenges faced by the Project.

INTRODUCTION

The Wabash River Coal Gasification Repowering Project (the Project) is a joint venture of Destec Energy, Inc., (Destec) of Houston, Texas and PSI Energy, Inc. (PSI) of Plainfield, Indiana, who will jointly develop, design, construct, own, and operate a commercial coal gasification combined cycle (CGCC) power plant at PSI's Wabash River Generating Station in West Terre Haute, Indiana. PSI will be responsible for the new power generation facilities and modification of the existing unit, while Destec will be responsible for the coal gasification plant.

With this Project, Destec and PSI are participating in the U.S. DOE's Clean Coal Technology Program to demonstrate the coal gasification repowering of an existing generating unit affected by the Clean Air Act Amendments. The Project will repower one of the six units at PSI's Wabash River Generating Station. The CGCC power plant will produce a nominal 262 (net) MW of clean, energy efficient capacity for PSI's customers. The Project will use locally mined high sulfur coal and outperform Phase II requirements of the Clean Air Act Amendments. The net plant heat rate will be approximately 9,000 BTU/kwh (HHV) and SO₂ emissions are expected to be less than 0.02 lbs/MMBTU of fuel. Upon startup in 1995, the Project will be the largest operating single-train coal gasification combined cycle plant in the United States.

The Project will dispatch as base load in PSI's system on the basis of both efficiency and environmental emissions and will be in operation as a PSI generating resource for at least 25 years. The Project is expected to produce some of the lowest cost electricity on the PSI system. The DOE Clean Coal Program Demonstration Period will cover the first three years of operation. The DOE investment in the Project is essential to ensuring the success of the first fully integrated commercial CGCC repowering project in the United States. Ultimately, efficient and clean CGCC technology can meet both domestic and global energy and environmental needs.

PROJECT HISTORY

Background

The Destec Coal Gasification process was originally developed by The Dow Chemical Company during the 1970's in order to diversify its fuel base from natural gas to lignite and other coals. The technology being used at Wabash is an extension of the experience gained from that time through pilot plants and up to the Louisiana Gasification Technology, Inc. (LGTI) facility in Plaquemine, Louisiana. LGTI is a 160 MW coal gasification facility which has been operating since April 1987.

Using data and experience gained at LGTI, Destec approached PSI in 1990 and discussions concerning the Wabash Project were initiated. Subsequently, Destec and PSI formed a joint venture for the purpose of participating in the U.S. DOE's Clean Coal Technology Program. In September 1991, the Project was selected by the U.S. DOE as a Clean Coal Round IV project to demonstrate integration of an existing PSI steam turbine generator and auxiliaries, a new combustion turbine, a heat recovery steam generator, and a coal gasification facility to achieve improved efficiency and reduced emissions. In July 1992, a Cooperative Agreement was signed with the U.S. DOE. Under the terms of this agreement, the Wabash River Coal Gasification Repowering Project Joint Venture will develop, construct, and operate a coal gasification combined cycle (CGCC) facility and the U.S. DOE will provide cost-sharing funds for construction and a three year Demonstration Period.

Project Organization and Structure

In general, Destec has responsibility for financing, construction, and operation of the gasification portion of the Project, and PSI has responsibility for financing, construction, and operation of the power generation portion of the Project. The Project will involve a construction period of approximately two years and an operating period of at least 25 years.

Two agreements establish the basis for the relationship between PSI and Destec. The Joint Venture Agreement created the Wabash River Coal Gasification Repowering Project Joint Venture in order to administer the Project under the DOE Cooperative Agreement. The

Gasification Services Agreement includes the commercial terms between PSI and Destec under which the Project will be developed and operated. The structure of the Gasification Services Agreement allows the Project to be integrated for high efficiency and provides for the use of common facilities to eliminate duplication. The major provisions of the Gasification Services Agreement include:

PSI Responsibilities -

- build and operate the power generation facility
- furnish Destec with a site, coal, electric power, and other utilities
- pay a monthly fee to Destec for gasification services

Destec Responsibilities -

- build and operate the coal gasification facility
- guarantee performance of the coal gasification facility
- deliver syngas and steam to the power generation facility.

PROJECT TECHNICAL DESCRIPTION

Design

The Destec gasification process features an oxygen-blown, two stage entrained flow gasifier. A process block flow diagram is shown in Figure 1.

In the Destec coal gasification process, coal is ground with water to form a slurry. It is then pumped into a gasification vessel where oxygen is added to form a hot, raw gas through partial combustion. Most of the noncarbon material in the coal melts and flows out of the bottom of the vessel forming slag - a black, glassy, nonleaching, sand-like material. The hot, raw gas is then cooled in a heat exchanger which produces high pressure steam. Particulates, sulfur and other impurities are removed from the gas before combustion to make it acceptable fuel for the gas turbine.

which produces approximately 192 MW of electricity with syngas fuel. The Project is the first application of advanced gas turbine technology for syngas fuel. A heat recovery steam generator recovers gas turbine exhaust heat to produce high pressure steam. This steam and the steam generated in the gasification process supply an existing steam turbine generator in PSI's plant to produce an additional 104 MW. Plant auxiliaries in the power generation and coal gasification areas consume approximately 34 MW, for a nominal net power generation for export of 262 MW.

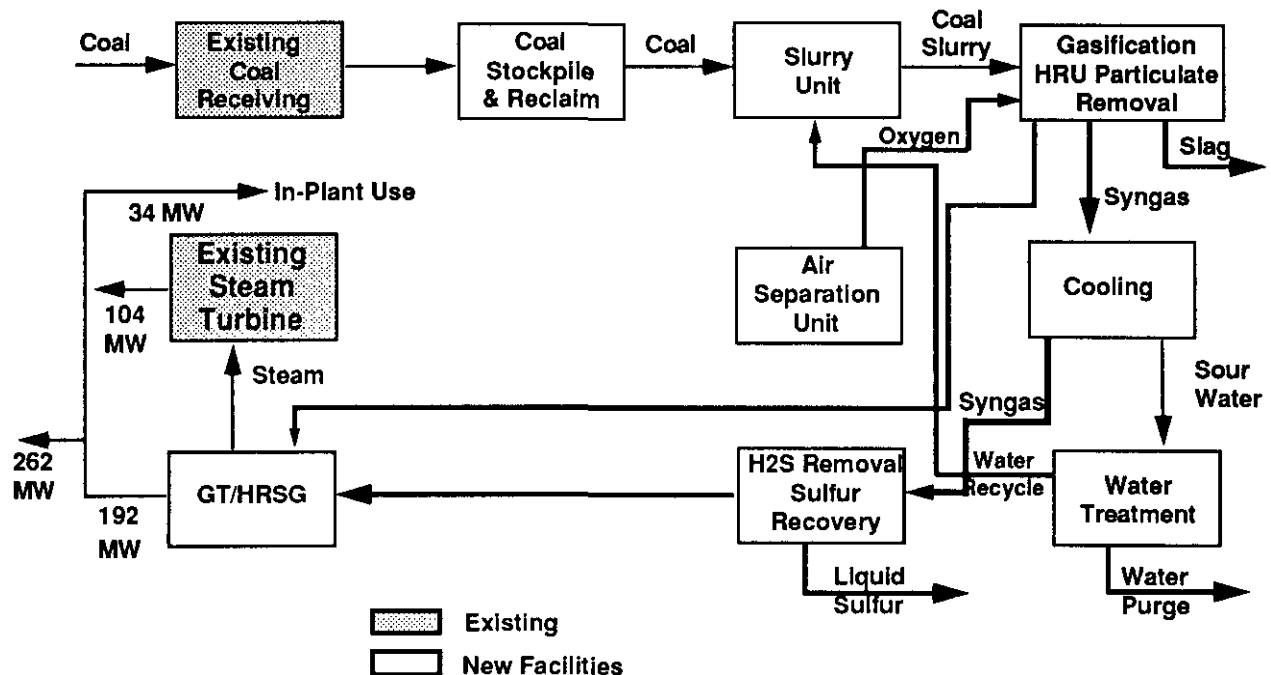


Figure 1 Block Flow Diagram

Several novel technology applications included the Project are:

- **Hot/Dry Particulate Removal** will be demonstrated at full commercial scale
- **Syngas Recycle** will provide fuel and process flexibility while maintaining high efficiency
- **A High Pressure Boiler** will cool the hot, raw gas by producing steam at a pressure of 1,600 psia

- **A High Pressure Boiler** will cool the hot, raw gas by producing steam at a pressure of 1,600 psia
- **A Dedicated Advanced Design Oxygen Plant** will produce 95 % pure oxygen for use by the Project
- **Integration Between the Heat Recovery Steam Generator and the Gasification Facility** has been optimized to yield higher efficiency and lower operating costs.

The new power generation facility will also include additional water treatment systems. The combustion turbine has steam injection for NO_x control. The amount of this injection flow is reduced compared to conventional systems because the syngas burned in the combustion turbine is moisturized at the gasification facility, making use of low level heat in the process. This flow is continuously made up at the power block by clarification and treatment of river water.

The CGCC plant will have two commercial byproducts during operation. Elemental sulfur removed via the gas clean-up systems will be marketed to sulfur users. Slag, a sand-like byproduct from the gasifier, will be available for use as a construction material.

Operations

Destec and PSI will independently operate their respective gasification and power generation facilities. Operating interface parameters and other key data will be interchanged continuously between the gasification and power generation control rooms. In normal operation, syngas production will follow combustion turbine fuel demand. Thermal balance between the facilities is flexible to a certain extent, utilizing the heat recovery steam generator and gasification facility heat exchangers, and will follow the syngas production.

Operation of the facilities will be closely coordinated during startup and shutdown. The combustion turbine operates on auxiliary fuel (oil) at low loads during startup and shutdown. A "flying switch" will be made to syngas and the combustion turbine will ramp up to full load at its normal rates.

Cost and Efficiency

Integration of the new and existing power generation facilities and the new gasification facility have resulted in lower installed cost and better efficiency than other "environmentally equivalent" coal based power generating projects. Reduced development effort and a shorter schedule have also resulted from choosing to repower an existing station rather than developing a greenfield installation. This advantage is evident from the rapid development and construction progress to date (discussed below).

The net plant heat rate for the entire new and repowered unit is expected to be approximately 9000 Btu/kWh, representing an approximate 20 percent improvement over the existing unit. Certain major component manufacturer margins and guarantees (combustion turbine, HRSG, HTHRU, *etc.*) are included in this energy balance calculation; actual operation is expected to be slightly better. This heat rate will be among the lowest of commercially operated coal-fired facilities in the United States. The Project is expected to produce some of the lowest cost electricity on the PSI system.

Repowering the existing unit, and utilizing the existing site facilities mentioned above, in addition to the existing steam turbine generator, auxiliaries, and electrical interconnections, represent an installed cost savings of approximately \$30 to \$40 million as opposed to an entirely new, greenfield installation.

The total estimated installed cost for the Project is \$362 million. This estimated figure includes escalation through 1995, environmental and permitting costs, and startup costs. On this basis, the total estimated installed cost of the project is approximately \$1,380 per kW of net generation. The U.S. Department of Energy's Clean Coal Technology Program (Round IV) provides partial funding for the project (\$198 million for construction and a three year demonstration period). PSI and Destec will provide the balance of the funds for their respective portion of the job. The DOE funding reduces the estimated installed cost to less than \$900 per kW of net generation.

Environmental Benefits

The plant will be designed to substantially outperform the standards established in the Clean Air Act Amendments (CAAA) for the year 2000. The Destec gasification technology to be employed will remove at least 98 percent of the sulfur in the coal. Expected SO₂ emissions will be less than 0.02 pounds per MMBTU of fuel. NO_x emissions from both the gasification block and the power block are expected to be less than 0.7 lb/MWh. CO₂ emissions will also be reduced, approximately 20 percent on a per kilowatt-hour basis by virtue of the increased system efficiency. Figure 2 compares emissions of current Wabash Unit 1 with expected emissions from the Project. By providing an efficient, reliable and environmentally superior alternative to utilities for achieving compliance with the CAAA requirements, the Wabash Project will represent a significant demonstration of Clean Coal Technology.

A. EXPECTED PROJECT EMISSIONS

CGCC EMISSIONS	SO ₂	NO _x	CO	PM	PM-10	VOC
Gasification Block Tons/Yr.	23	18	124	25	20	12
Power Block Tons/Yr.	204	774	374	46	42	13
Total CGCC Tons/Yr. (note 1)	227	792	498	71	62	25

B. COMPARISON TO EXISTING UNIT

EMISSIONS, LBS/MWH	SO ₂	NO _x	CO	PM	PM-10	VOC
Unit 1 Boiler	38.2	9.3	0.64	0.85	0.85	0.03
CGCC	0.21	0.75	0.47	0.07	0.06	0.02
EMISSIONS, LBS/MMBtu						
Unit 1 Boiler	3.1	0.8	0.05	0.07	0.07	0.003
CGCC	0.02	0.08	0.05	0.01	0.01	0.003

Note: 1) Based on 2,065,600 MW/hr estimated annual generation (262 MW at 90% capacity factor)

Figure 2 - Environmental Emissions

ACTIVITIES TO DATE

Site Selection and Preparation

Early site feasibility studies resulted in locating the new coal gasification repowering facilities northwest of PSI's existing Wabash River Generating Station (see Figure 3). The land for the Project was donated by the Peabody Coal Company. This property was formerly the Viking Mine, which once supplied the existing station with coal.

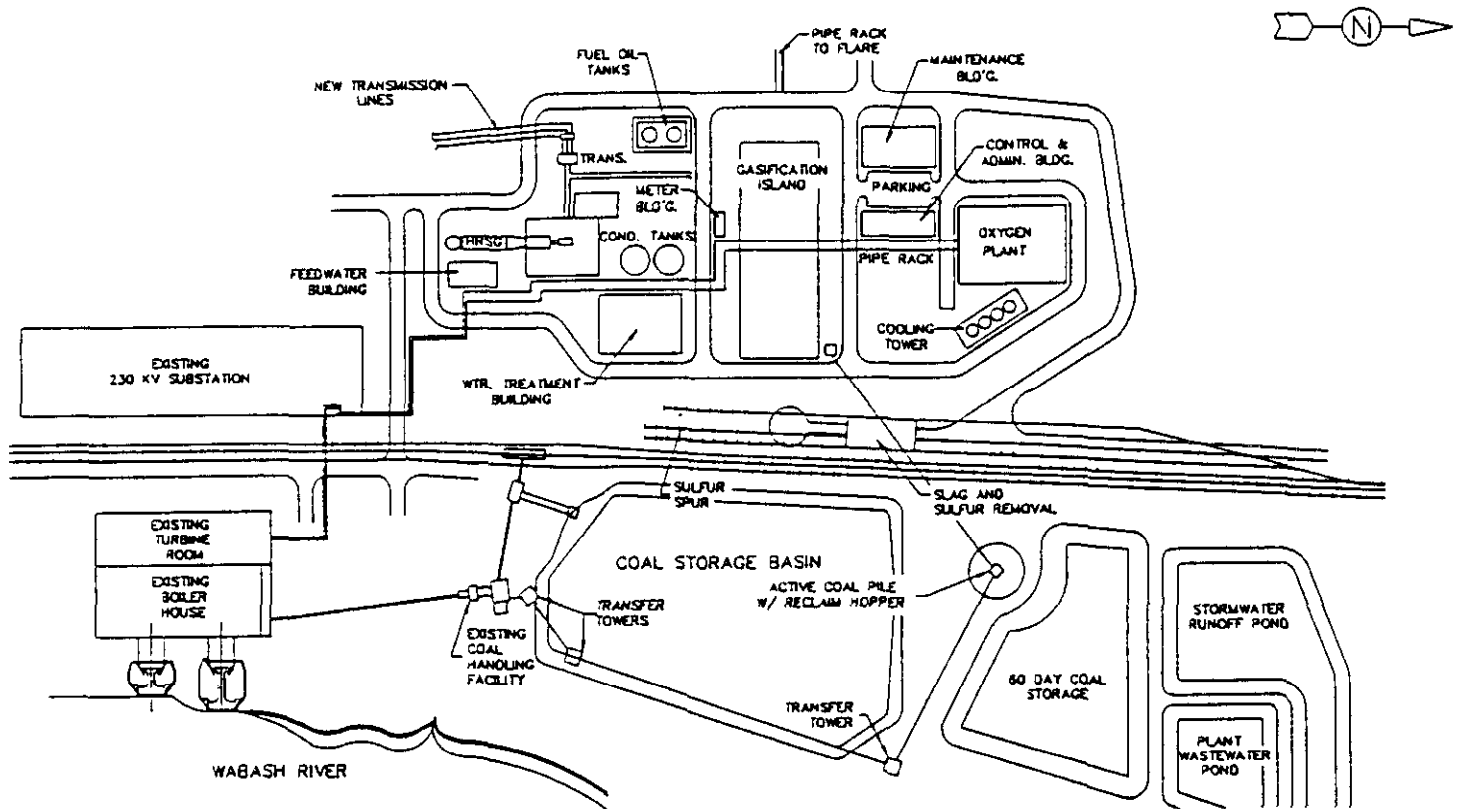


Figure 3 - Wabash River Coal Gasification Repowering Project Site

Locating the Project adjacent to the existing Wabash Generating Station minimized the cost of expensive steam piping connecting the existing Unit 1 steam turbine and the new heat recovery steam generator. Other existing facilities to be used by the Project include the railroad, coal unloading facilities, steam turbine, condenser and auxiliaries, and the ash pond. Although the integration of the coal gasification project with the existing station provides efficiency and cost advantages, the limitations on space have presented challenges during construction. Among these is the challenge of managing a construction manpower peak of over 400 people for two jobs on a small site.

Additional site challenges that have been encountered include: 1) the need to reorient the physical layout of the gasification plant to protect against potential subsidence (based on site-specific data obtained during the engineering phase); and 2) unstable mine spoils that made planned construction laydown and parking areas unsuitable for use.

Permitting and Regulatory Approval

Obtaining environmental permits and regulatory approvals were two major challenges to development of the Project. As a DOE sponsored project, the Project was subject to the requirements of the National Environmental Policy Act (NEPA). PSI, Destec and two environmental consulting firms were involved in the preparation of a detailed environmental information volume which was the basis for DOE's development of an Environmental Assessment of the impact of the Project. The favorable NEPA assessment resulted in DOE issuing a Finding of No Significant Impact (FONSI) in May 1993. Although the DOE supported the joint venture's efforts by expediting the review process, the FONSI was received approximately six months after the milestone date for this activity established in the original Project schedule. The Project was the first of its scope, under the DOE Clean Coal Technology Program, to obtain this status. The FONSI also reflects the advantage of a repowering application over greenfield construction.

The Project was also required to obtain other environmental permits. The most significant of these was the air permit. Because Destec has responsibility for the gasification plant and PSI has responsibility for the power generation portion of the Project, it was necessary for Destec

and PSI to both obtain separate permits. However, for consistency and expediency, it was desirous to perform air quality modeling studies on a combined basis. The total project was considered a modification to the PSI Wabash River Generating Station and environmental impact information was provided in combined form when possible. Communications between PSI, Destec, environmental consultants, and the permitting agencies (both state and federal) were managed through a multitude of face-to-face meetings. Both Destec and PSI received the requisite air permits in May 1993.

In addition to the challenge of permitting a joint venture-type project, the Project faced the additional challenge of educating the permitting agencies about CGCC. Destec was specifically concerned about protection of proprietary technology and establishing a reasonable permitting precedent for future CGCC plants. PSI was concerned about obtaining credit for sulfur emission reductions. After diligent work by all, these goals were obtained. This is another example of a CGCC precedent being set by the Wabash Project, including a new emission credit methodology for CGCC technology.

Finally, in order for PSI to include its portion of the Project in its ratebase, it was necessary to obtain a Certificate of Need from the Indiana Utility Regulatory Commission (IURC). PSI and Destec both prepared testimony for the IURC that allowed a Certificate of Need to be issued to the Project in May 1993. This activity opened the Project to additional review. The aspects of the Project which make the Project attractive - innovative technology applied in a commercial setting at a large scale and supported by DOE funding - were the very aspects that required careful, and precedent-setting, regulatory review.

Again, careful coordination between PSI and Destec, combined with clear communication between PSI and the Indiana Utility Regulatory Commission (IURC) allowed the Project to receive a Certificate of Need despite opposition from others who wanted to supply capacity to PSI's system and an IURC that was previously unfamiliar with CGCC. Careful structuring of the commercial arrangements between PSI and Destec, especially with regard to risk (through the Gasification Services Agreement), was essential to developing a project that could obtain regulatory approval. PSI received the required Certificate of Need in May 1993.

Construction Activities

Extensive pre-construction site work was required to level the Project site. Over 1 million yards of dirt was moved in 1993 prior to mobilization of construction contractors. Although construction work is now approximately 50% complete, these activities have been hampered by unusual weather conditions. The summer of 1993 was the wettest summer in Indiana history (rains reached 500-year flood level). This was followed by the wettest November since 1888 and snow from Halloween through Easter of this year. In addition, Indiana experienced the coldest January on record, and ice storms shut down construction work in February. In order to stay on schedule, both PSI and Destec have selectively employed 7-day construction schedules while trying to balance budget and schedule needs. Given the weather and schedule constraints, the size of the small site, and the complexity of the job, communication and coordination are essential elements of success.

During the last year, the following major milestones have been achieved:

- full mobilization of construction crews to the site;
- gas turbine received and set;
- HRSG field erection begun;
- Water and Wastewater Treatment facility constructed;
- Air Separation Unit column constructed and compressors set;
- gasifier vessels field erected and set in structure;
- control buildings constructed.

Peak construction activity is occurring now -- over 400 workers are on-site daily working for a host of contractors and subcontractors, all ultimately reporting to either Destec or PSI. Project management expertise and coordination with, and support from, the local labor unions and contractors has been critical to maintaining Project schedule.

Other construction challenges that have been encountered include:

- transport of large equipment to the site (some shipments had less than 2" clearance), despite flooded rivers, transportation strikes, and cross-country transport logistics;

- coordination of timing for interconnection responsibilities between the Destec and PSI portions of the Project; this challenge became critical as permitting and weather delays compressed the original construction schedule;
- the need to carry out a complex construction job with minimal impact to the existing PSI generating station;
- the need to make several heavy equipment lifts (up to 600,000 lbs) in a short period of time without disrupting other site activities.

To date these challenges have all been successfully met.

Startup and Commissioning Activities

Startup and commissioning activities have already been initiated. The Project will create approximately 100 new operations and support jobs. During 1993, staffing philosophies were finalized and by early 1994, hiring was in progress. Training activities are now the major priority. For PSI, which has limited experience with gas fired turbines new training activities have been developed. Among these is a full scale power block simulator developed with funding from EPRI. This simulator is being used as a training tool for the Project, but, in abbreviated form, can also be used for future CGCC projects.

Detailed commissioning packages are being developed jointly between construction and operating personnel. In addition, coordination activities between Destec and PSI have been a major area of activity.

FUTURE CHALLENGES

The major challenges facing the Project over the next year are to complete construction activities on schedule and achieve a smooth startup. Although construction activities are on track at this point in time, the abnormal weather and transportation difficulties have taken much of the slack out of the schedule.

Coal selection activities are also in progress at this time. Efforts to optimize both the cost of coal and the gasification plant performance, for optimal startup activities, are on-going.

Commissioning activities for equipment will begin as early as the fourth quarter of 1994. By mid-August of 1995, the Project is expected to be in commercial operation. Training will continue to be a priority for the remainder of 1994. Coordination between construction and operations, and PSI and Destec, will be critical in 1995.

TAMPA ELECTRIC COMPANY
INTEGRATED GASIFICATION COMBINED CYCLE PROJECT
CURRENT STATUS

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INTRODUCTION AND OVERVIEW

This project was originally conceived to respond to the Program Opportunity Notice (PON) for DOE's Round III solicitation as part of the Clean Coal Technology program. The project was one of the 13 selected from 49 applicants. Notification of award was received from DOE in January 1990, by TECO Power Services (TPS) one of the original project partners.

The originally proposed project was a 120 MW air-blown fixed-bed gasifier supplying a GE 6EA combustion turbine/combined cycle power plant, and included an in-line zinc ferrite hot gas clean-up (HGCU) system. The general objective of this project was to demonstrate cost competitive integrated gasification combined cycle with hot gas clean-up.

Due to difficulties encountered with finalizing the power sales agreement with the originally intended power purchaser, the participant began the search for other local (Florida) purchasers for the unit's output. What became obvious was that for a Florida utility to accept our IGCC concept, a more efficient, more reliable, and more cost effective arrangement would be necessary.

To meet these needs, we altered the project's arrangement to include a General Electric (GE) 7F(A) combustion turbine (CT)/combined cycle (CC) system to significantly increase the power island efficiency and output. We added a Texaco oxygen-blown entrained-flow gasifier to increase the project's environmental acceptance and reliability due to the Texaco gasifier's proven track record at Cool Water. We added an Air Separation Unit (ASU) and coupled the excess nitrogen (N_2) to the inlet of the CT to increase system output, reduce NO_x emissions and increase overall plant efficiency. In order to enhance the HGCU performance, the sorbent was changed to zinc titanate. Finally, to ensure system reliability, we opted to install a conventional 100% cold gas clean-up (CGCU) system in parallel with a 50% HGCU system to insure that the IGCC system would be able to operate regardless of the status of the HGCU system.

With the changes proposed, the system that resulted was more efficient, more reliable, and resulted in reduced emissions. To be more commercially and economically acceptable, a size of 250 MW was selected as compared to the originally proposed 120 MW. In addition, Tampa

Electric Company (TEC) was now the Participant and the project would not be a Power Sales Agreement type IPP unit as originally proposed by TPS. TEC would use this plant to meet its generation expansion needs. Also, the Florida Public Service Commission acknowledged that, with the DOE partial funding, this unit was indeed TEC's least cost power option.

It is important to note that the originally proposed project called for a 50/50 cost shared arrangement between the participant and DOE. DOE would provide \$100,000,000 for capital expenses and \$20,000,000 for O&M support during the two (2) year demonstration period. Because the DOE funds were fixed, the project's support from DOE for the 250MW unit, on a percentage basis, changed from 50% to about 20%. In essence, DOE got a more than twice as large project for their contribution, and TEC got the financial support to ensure a least cost capacity addition; a win-win-win situation for TEC, its Customers, and the DOE.

By successfully completing this demonstration, TEC's Polk Unit #1 will be in a position to demonstrate to the domestic United States utility industry, that IGCC can fulfill future energy needs, will utilize the US's most abundant and economical fuel, will be environmentally superior, and will be more cost competitive than other coal burning options.

This has benefits from both a domestic and world wide viewpoint. We all know the sensitivities in the original clean coal program. Emphasis was on using only American made products. The federal government didn't want to spend US tax dollars outside the US. What is now realized is that, with so little generation expansion in the US, transfer of our "Clean Coal Technologies" to places outside the US enhances US cash flow, has the potential to create new U. S. jobs, and benefits world wide emissions simultaneously. This is because successful demonstration of clean coal technologies like the Polk IGCC project will create a world wide demand for the technical know-how developed in the Clean Coal Technology Program, plus create demand for the hardware developed via this demonstration such as the American-made GE 7F combustion turbine.

GOALS OF THE PROJECT

Obviously, the main objective of any power plant is to provide electric power for the utility's

Customers. This unit is an integral part of Tampa Electric Company's generation expansion plan. That plan requires baseload capacity to be in service in the summer of 1996. TEC's objective is to build a coal-based generating unit providing reliable, low cost electric power, using IGCC technology to meet those requirements.

From DOE's standpoint, this project is expected to demonstrate the technical feasibility of a commercial scale IGCC unit using hot gas clean-up technology. In addition, demonstration of the oxygen-blown entrained-flow IGCC technology is expected to show that such a plant can achieve significant reductions of SO₂ and NO_x emissions when compared to existing and future, conventional coal-fired power plants.

Via successful demonstration of this IGCC project, TPS will not only satisfy DOE's goal for providing a viable technology choice for future utility needs, it will also provide the opportunity for TPS to become recognized as a leader in this field and provide us opportunities to develop additional projects while "commercializing" the technology for both TPS and DOE.

Participants

Below are the major project participants and a discussion of their involvement.

U. S. Department of Energy

The Department of Energy has entered into a Cooperative Agreement, for demonstrating IGCC technology with HGCU, with TEC under Round III of the Clean Coal Technology (CCT) Program. Administration of DOE's role and responsibilities rests in DOE's Morgantown Energy Technology Center in West Virginia.

Tampa Electric Company

Tampa Electric is responsible overall for the implementation and operation of this project. TEC is the "Participant" and has repayment responsibilities to DOE.

Tampa Electric Company is an investor-owned electric utility, headquartered in Tampa, Florida. It is the principal, wholly owned subsidiary of TECO Energy, Inc., an energy related holding

company heavily involved in coal mining, transportation, and utilization. TEC has about 3200MW of generating capacity, of which 97% is coal-fired. TEC has about 470,000 customers in an area of about 2,000 square miles in west-central Florida, primarily in and around Tampa, Florida.

TEC has five generating stations; two are coal-fired (2850MW), two are heavy oil-fired (250MW), and one is natural gas-fired (11MW). TEC also has four combustion turbines with about 160MW of generating capacity, used for start-up and peaking.

TECO Power Services

TECO Power Services (TPS) is also a subsidiary of TECO Energy, Inc., and an affiliate of TEC. This company was formed in the late 1980's to take advantage of the opportunities in the non-utility generation market. TPS has recently started up a 295MW natural gas-fired combined cycle power plant in Hardee County, Florida. Seminole Electric Cooperative and Tampa Electric Company are purchasing the output of this plant under a power sales agreement.

TPS is responsible to Tampa Electric for the overall project management for the DOE portion of this IGCC project. TPS will also concentrate on commercialization of this IGCC technology, as part of the Cooperative Agreement with the U.S. Department of Energy.

Other Participants

Other participants are GE, General Electric Environmental Services (GEESI), Texaco, Air Products, Raytheon Engineers & Constructors, Monsanto, MAN GHH, Steinmüller and Bechtel which acts as our engineer and construction manager. We consider these participants to be our partners in implementing this important project.

PROJECT SITE

The Polk Power Site will be built on a Central Florida inland site in southwestern Polk County, Florida. The site, about 11 miles south of Mulberry, is a tract previously mined for phosphate and is basically unreclaimed. This site was intended to be used for TEC's next generation addition, originally a 75MW simple cycle combustion turbine (CT) scheduled to be in service

in mid-1995. The site was selected by an independent Community Siting Task Force, commissioned by TEC to locate a site for its future generating units.

The seventeen person group consisted of environmentalists, educators, economists, and community leaders. The study, which began in 1989, considered thirty-five sites in six counties. The Task Force recommended three tracts in southwestern Polk County that had been previously mined for phosphate. These sites had the best overall environmental and economic ratings.

The selected site is about 4300 acres. About one-third of it will be used for the generating facilities. As part of this overall plan, the existing mine cuts will be modified and used to form an 850 acre cooling reservoir.

Another one-third of the site will be used for creating a complete ecosystem. It will include uplands, wetlands, and a wildlife corridor. This will provide a protected area for native plants and animals. The final one-third of the site will be unused, and will be maintained for site access and will provide a visual buffer.

COST

The current expected cost for this unit is about 500 million dollars. Being a demonstration project, we are finding every day that we haven't yet fully defined all of the technical requirements for the project. As we develop these aspects, we find that each one has an associated cost impact; some positive, some negative. Even the major participants such as General Electric and Texaco are still optimizing designs related to this project. Although the GE 7F is a commercial product, General Electric is still polishing integration concepts for the low BTU/IGCC system. The same holds true for Texaco. Their gasification system is well proven, but as they have worked to integrate it into a cost effective IGCC system, they too are learning more and more about how their system impacts on the other parts of the project.

Back to the 500 million dollars. If you divide that figure by 250MW, it results in about \$2,000/KW. When you apply the DOE funding, this number drops to about \$1,600/KW; still not as low as we would like it to be, but for a first of its kind commercial installation, it is not

too bad, especially when considering that this figure includes both CGCU and HGPU, plus significant site development costs not normally expected for a new site. What utilities look for are cost effective, reliable ways to install new operating power plants. However, many times, capital costs are not the total deciding factor on what technology to use.

In this day and age, coal-based generation is increasingly more difficult to permit in the U. S. The operating costs for oil and/or natural gas are higher than coal, especially when you look at the recent past and the potential volatility of these fuel prices. In addition, the IGCC concept offers emissions which approach those of the natural gas-fired combustion turbines. That's why we believe, when all factors are considered, IGCC represents Tampa Electric Company's best option for this new capacity requirement.

The primary IGCC competition in the short term U.S. market is natural gas-fired combined cycle. For the IGCC to compete, long term natural gas prices must rise relative to coal prices, and/or IGCC capital costs must decrease. As we all know there is a significant uncertainty about the long term aspects of natural gas pricing compared to coal costs. Natural gas prices have in fact increased over the last few years. Whether these trends continue, and how long they continue, is anybody's guess.

Natural gas prices are not in the IGCC technology suppliers' control but are still very important. Capital cost is in the control of the IGCC technology suppliers. Reduction in capital costs of IGCC technology is required to ensure its long term competitiveness. Capital cost reduction probably represents the most significant challenge for IGCC technology suppliers. Through economies of scale or other means, such as reduced design margins, repetitive designs and improved fabrication techniques, IGCC capital cost must be reduced for the IGCC technology to be consistently competitive in the future.

Tampa Electric Company's economic justification for this project has been, in large part, dependent upon to the \$120 Million (now \$130 Million due to design changes and project enhancements) funding from the DOE. The Clean Coal Technology Program provides a bridge between the economics of today and those of the future. Tampa Electric is proud to be taking

a leadership position applying these funds to further IGCC technology for future use by other utilities in the U.S. and the world.

SCHEDULE

The total IGCC project, is expected to be put into service July 1996. Originally, we had considered using the 7F combustion turbine in a simple cycle mode to meet Tampa Electric Company's peaking capacity requirements for the summer of 1995. As Tampa Electric Company has continued to look at it's generation needs, this peaking requirement has shown a recent shift allowing us to move the installation of the 7F CT to coincide with the overall IGCC requirements for total system operation in July of 1996. This will allow us to perform more efficient and effective site development and overall project installation. Due at least in part to unexpected delays in obtaining final permit approvals, the July 1996 commercial operation date will probably occur sometime between July and October 1996, depending on the date when the permit is actually received.

The current schedule requires permits to be received in mid 1994. This will allow us to begin construction on the site which requires a massive amount of reclamation development work and considerable time to convert the existing mine cuts into a usable cooling water reservoir. The two main pieces of equipment impacting our schedule are the 7F Combustion Turbine and the radiant syngas cooler. We started preliminary site work related to the construction of the cooling ponds in May of this year. Major site construction and foundations will start about the middle of September 1994.

Most of the equipment is scheduled for delivery in early 1995 which will provide for extreme flexibility in construction sequencing. Specifically, the major CT components are scheduled for March/April 1995 delivery, with the radiant syngas cooler expected to arrive at the site in May 1995.

Our Cooperative Agreement requires us to test four (4) different fuels during the first two (2) years after commercial operation. These coals will be classic eastern coals; eastern being defined as east of the Mississippi. We would expect to test burn such coals as Pittsburgh 8,

Illinois 6, Kentucky 9, Elkhorn 3, etc. The results of these tests will provide data for utilities in many coal producing areas to be able to determine operating characteristics and economics related to using IGCC in their areas. The results of these tests will compare this unit's efficiency, operability, and capital costs, and report on each of these specific test coals against the design basis coal (Pittsburgh 8).

These results should provide a menu of operating parameters and costs which can be used by utilities in the future as they make their selection on methods for satisfying their generation needs, in compliance with environmental regulations. After the initial two (2) year demonstration period, TEC will continue to report the unit's performance on it's most economical fuels for two (2) additional years or through July 2001 whichever is sooner.

THE PROJECT

Overview

The Polk Power Station Unit #1 IGCC Project will contain two major pieces which will in combination produce 250MW of total IGCC capacity in mid-1996. The first piece will be the advanced CT/combined cycle facilities. The second piece will be the gasification facilities.

Part of this DOE CCT project will be to test and demonstrate a new HGCU technology. With the exception of the HGCU, only commercially available equipment will be used for this project. The approach supported by DOE is the highly integrated arrangement of these commercially available pieces of hardware or systems, in a new arrangement which is intended to optimize cycle performance, cost, and marketability at a commercially acceptable size of nominally 250 MW (net). Use of the HGCU will provide additional system efficiencies by demonstrating the cycle improvements realized from cleaning syngas at a temperature of about 900°F rather than utilizing more traditional CGCU methods, cooling the gas to about 100°F before sulfur removal is accomplished. This low temperature process has the disadvantage of the irreversible cooling losses and associated reheating before admitting the syngas to the CT.

Historical Review

Gasification of coal has been around for quite some time. In its early uses, it provided a cheap

source of town gas for localities where natural gas was unavailable. Coal gasification has also historically been used to provide raw materials for chemical and refinery processes.

Combustion turbines have also been used for quite some time; generally in smaller sizes and with a history of availability problems. In the recent past, with the emphasis on lowering capital costs and increasing efficiency, most CT manufacturers have gone to the larger capacity and the higher firing temperature technology used in jet aircraft engines.

Oxygen production in air separation plants has also been used widely in chemical manufacturing and refinery applications, but not generally for utility applications. The size of the equipment, required for utility use, and the cryogenic nature of the air separation process are all new adventures for utilities.

Fortunately, the experience gained at Cool Water, a 100MW IGCC plant demonstrated successfully in the late 1980s, has and will continue to provide us a good data base to use for extrapolation to our larger and commercially acceptable size of IGCC unit. Also, the HGCU pilot work done over the last decade by GEESI will result in improved efficiencies and potentially eliminate or significantly reduce the water discharge and process handling problems associated with traditional CGCU systems.

The essence of this is that the historical experience of the individual components used in this project will ease the integration of these systems to provide us with the results we are seeking: a highly efficient, reliable, and improved emissions type IGCC power plant.

Gasification

This unit will utilize commercially available gasification technology as provided by Texaco in their licensed oxygen-blown entrained-flow gasifier. In this arrangement, coal is ground to specification and slurried in water to the desired concentration in rod mills. The unit will be designed to utilize about 2000 tons per day of coal (dry basis). This coal slurry and an oxidant (95% pure oxygen) are then mixed in the gasifier burner, then produce syngas with a heat content of about 250-300 BTU/SCF (LHV). The oxygen will be supplied from an Air

Separation Unit (ASU). The gasifier is expected to achieve greater than 95% carbon conversion in a single pass. The gasifier is a single vessel exhausting into one radiant syngas cooler where the gas temperature will be reduced. After the radiant cooler, the gas will then be split into two (2) parallel convective coolers, where the temperature will be cooled further to about 900°F. This will enable us to treat a HGCU stream of about 25-35MW capacity without creating significant flow disturbance for the remainder of the system.

The CGCU system will be an enhanced amine scrubber type. Sulfur species removed in the HGCU and CGCU systems will be recovered in the form of sulfuric acid. This product has a ready market in the phosphate industry in the central Florida area. It is expected that the annual production of about 37,000 tons of sulfuric acid from this nominal 250MW (net) IGCC unit will have minimal impact on the price and availability of sulfuric acid in the phosphate industry.

Most of the unconverted carbon exits the bottom of the gasifier/radiant syngas cooler into the slag lockhopper where it is mixed with water. These solids generally consist of slag and uncombusted coal fines. As they exit the slag lockhopper, these non-leachable products are readily saleable for blasting grit, roofing tiles, and construction building products. TEC has been marketing a similar slag from its existing units for such uses for over 25 years.

Obviously, the water in the slag lockhoppers requires treatment before it can be discharged or reused. All of the water from the gasification process will be cleaned and reused, thereby having no requirement for discharging process water from the gasification system.

Air Separation Unit

The Air Separation Unit (ASU) will use ambient air to produce oxygen for use in the gasification system and nitrogen which will be sent to the CT. The addition of nitrogen in the CT combustion chamber has dual benefits. First, since syngas has a substantially lower heating value than natural gas, a higher mass flow is needed to maintain total turbine input. Second, the nitrogen acts to control potential NO_x emissions by reducing the combustor flame temperature.

The ASU will be sized to produce about 2000 tons per day of 95 % pure oxygen and about 6300 tons per day of nitrogen. The ASU is being designed and constructed as a turnkey project.

HGCU

The HGCU system is being developed by General Electric Environmental Services, Inc. (GEESI). This process is undergoing pilot plant testing at GE's laboratory facilities in Schenectady, NY. As previously noted, the successful demonstration of this technology will provide for higher efficiency IGCC systems.

One specific issue in the HGCU system for our project is the metal oxide sorbent being demonstrated. The sorbent material used will be either zinc titanate or a patented sorbent from Phillips Petroleum called Z-SORB. Both are more robust materials and more amenable to the oxygen-blown entrained-flow gasifier syngas than zinc ferrite, which is usually considered for air-blown gasifiers.

A regeneration system will produce a concentrated (about 13 %) SO₂ stream, which then will feed a sulfuric acid plant for production of the saleable acid by-product.

The feasibility of two (2) other support processes will be investigated for potential improvements to this process. In addition to the high efficiency primary cyclone being provided upstream of the HGCU system, a high temperature barrier filter will be installed downstream of the HGCU to protect the combustion turbine. Also, sodium bicarbonate, NaHCO₃, will be injected upstream of the primary cyclone for removal of chloride and fluoride species.

Combined Cycle

The main components of the combined cycle are the advanced combustion turbine (CT), heat recovery steam generator (HRSG), steam turbine (ST), and generators.

GE is currently optimizing arrangements for increasing fuel inlet temperature and also for lowering the pressure drop across the fuel inlet control valving. This has a compounding positive effect on cycle efficiency by also allowing a lower pressure in the ASU, requiring less

air and nitrogen compressor parasitic power. GE is currently finalizing testing on the combustion hardware to ensure satisfactory operation in the 7F while firing low BTU syngas.

The HRSG is installed in the combustion turbine exhaust to complete the traditional combined cycle arrangement and provide steam to a traditional steam turbine with a capacity of about 120MW.

No auxiliary firing is proposed within the HRSG. The HRSG will be used to recover the CT exhaust heat energy and high pressure steam production from the coal gasification (CG) plant. All high pressure steam will be superheated in the HRSG before delivery to the high pressure ST.

The ST will be designed as a double flow reheat turbine with low pressure crossover extraction. The ST/generator will be designed specifically for highly efficient combined cycle operation with nominal turbine inlet throttle steam conditions of approximately 1,400 psig and 990°F with 1,000°F reheat inlet temperature.

Integration

The key to success for the overall project will be the integration of the various pieces of hardware and systems. Maximum usage of heat and process flow streams can usually increase overall cycle effectiveness and efficiency. In our arrangement, benefits are derived from using the experience of other projects, such as Cool Water, to optimize the flows from different subsystems. For example, low pressure steam from the HRSG will be produced to supply heat to the CG facilities for process use. The HRSG will also receive steam energy from the CG syngas coolers to supplement the steam cycle power output. Low pressure steam will also be provided by the HRSG for condensate heating.

Probably, the most novel integration concept in this project is our intended use of the ASU. This system provides oxygen to the gasifier in the traditional arrangement, while simultaneously using what is normally excess or wasted nitrogen, to increase power output and improve cycle efficiency and also lower NO_x formation.

The heart of the integration concept is the distributed control system (DCS). Extreme effort is being exerted to insure early receipts of vendor information so that all aspects of the integration can be considered at the onset of the project. We are doing two specific things which we hope will maximize our chances of successful integration of all components and systems. First, we have and are continuing to do a thorough Hazop analysis to consider all the things that could go wrong, from a design standpoint, before the system gets to the field. The second thing will be an intense and a complete factory checkout and simulation to insure both the design and fabrication are as close to perfect as possible, even before the DCS leaves the manufacturer's shop.

Emissions

The primary source of emissions from the IGCC unit is combustion of syngas in the CT. The exhaust gas from the CT will be discharged to the atmosphere via the HRSG stack. Emissions from the HRSG stack are primarily NO_x and SO_x with lesser quantities of CO, VOC, and particulate matter (PM). SO₂ emissions are limited by permit regulations to 0.247 lb/mmBTU during the initial two (2) year demonstration period but will be limited to 0.17 lb/mmBTU thereafter. Similarly, for NO_x the limits will be 0.4 and 0.1 lb/mmBTU (81 ppmvd and 25 ppmvd). The emission control capabilities of the HGCU system are yet to be fully demonstrated. Therefore, some HGCU emission estimates are higher compared to estimated emissions from the CGCU system. After the completion of the initial 2-year demonstration period, the lower emission rates must be achieved for either CGCU or HGCU mode of operation, by the IGCC system, to meet permit requirements. It is expected that at least 96 percent of the sulfur present in the coal will be removed by the CGCU and HGCU systems.

The advanced CT in the IGCC unit will use nitrogen injection to control NO_x emissions during syngas firing. Nitrogen acts as a diluent to lower peak flame temperatures and reduce NO_x formation without the water consumption and treatment/disposal requirements associated with water or steam injection NO_x control methods. Maximum nitrogen diluent will be injected to minimize NO_x exhaust concentrations consistent with safe and stable operation of the CT. Water injection will be employed to control NO_x emissions only whenever backup distillate fuel oil is used.

COMMERCIALIZATION

As we reported last year at this conference, we have found that this technology is vastly different from what utilities are accustomed to using. The non-technical or business issues such as project management and contract administration also have significantly different requirements. The business issues must be successfully addressed by both the utilities and the different technology suppliers, in order for IGCC power plants to achieve ultimate commercial success. In our project, this has been a major task: meshing cultures from the utility, refinery industrial, and sulfuric acid industries. Last year at this time, some of the participants were only interested in their own agendas, now most realize that for their agendas related to IGCC to be realized, their attentions must be focused on making Polk IGCC a success. Although it has been very different for us, we have successfully achieved a team concept that will be the template for IGCC Units built in the future. We now have the team effort in place that will assure our Project's success, for all the participants.

The actual combustion of a fuel produces the side effects that many consumers are concerned about. The entire gasification industry needs to continue to develop methods for processing coal into fuel gas in a manner that minimizes emissions of environmentally sensitive constituents. There still will be required an intensified effort by technology vendors in the general gasification area and integration concepts to develop and implement improvements, in order to support long term commercial viability of IGCC.

One of the major hurdles we have had in this project, is adapting to the contracting requirements for these new and different technologies. The technology license typically provides information necessary to implement this technology, but usually not the equipment necessary to do it. When a utility buys a boiler, the supplier provides the required hardware as well as the technology, in the overall pricing as a total package. Guarantees are also significantly different from that with which utilities are accustomed to dealing. The license of a technology generally applies only to the process performance and not necessarily the overall end product. Licensors look towards equipment vendors to provide the equipment guarantees. This leads to split responsibilities and more complicated contracting. If the system doesn't work, then it's up to the utility to determine who is at fault and try to negotiate resolution of the problem. Because

the technology suppliers do not normally provide equipment, their level of liquidated damage support is considerably less than is usually available from equipment to utilities. A license is a small part of the overall project cost and the damages associated with that are very small and insufficient to protect the utility in case the equipment or technology doesn't work as intended by the licensor. Technology suppliers usually only provide process knowledge and, in some cases, equipment recommendations. They leave it up to the purchaser to determine how to implement the technology and engineer, develop, and buy the equipment and hardware necessary to get benefit from the license. What utilities need, and what we are now starting to develop now on the Polk Project, is for technology suppliers to increase their involvement to include the total project, not just their part of the project. For IGCC to be successful, technology suppliers need to expand their thinking like what is now being done on Polk.

Other opportunities that are seen, are for turnkey parts of the IGCC project. We are proceeding in our project to buy the air separation unit and the sulfuric acid plant on a turnkey basis. That means the supplier will engineer, procure, install, and start-up these plants. There was a proposal for them to operate the plant and sell us oxygen and nitrogen "over the fence". This alternative will continue to be evaluated by utilities as they look for ways to reduce the overall capital costs and make the IGCC system more competitive in the open market.

It is suggested that technology vendors could ease the overall burden and costs if they were to approach this technology similar to the way the boiler manufacturers used to do with the utility industry. Utilities would go to one vendor to buy the technology, equipment, and the guarantees. This certainly eased the burden for the utilities, but admittedly put more risk on the licensors or vendors. If technology suppliers and developers are to successfully participate in the utility market, they should seriously consider contracting strategies which simultaneously meet the needs of both the technology vendors and the utilities.

We are beginning to see a change in technology vendors' approaches to projects currently being pursued in the IPP arena. This has been mandated by the competitiveness of the market. Hopefully these changes will also be applied to conventional new IGCC plants. Technology suppliers are becoming more sensitive to the end users needs and requirements. They now

realize that if they are to sell a product, it must be packaged the way the user wants it and intends to use it.

The bottom line is still that both utility and technology suppliers must maintain flexibility and open mindedness in their approach to this new business. Both sides will have to change their way of normally doing business in order for the IGCC concept to proceed successfully. We have developed ways to bridge this gap for our project but it has been very difficult and slow in coming. Technology suppliers have generally been very reluctant to change their way of doing business. To reap the rewards for the massive utility industry market that is out there, they must be willing to make this compromise.

We are happy to report that since last year, we have seen noticeable improvements in the working relationships with our suppliers. The project organization is more of a team. We still have room for improvement, but based on the changes made from last year, we have no doubt that we will all succeed in our collective goal to demonstrate IGCC commercialization.

To achieve wide success for utilities, suppliers, and A/E's, we must all continue to accept the challenge in recognizing that flexibility and ingenuity, applied to both technical and business issues, will be the key to successful commercialization of IGCC. We now have achieved this success with our partners on our project and invite you to build on our approach to realize the tremendous benefits associated with IGCC Technology.

FUTURE

As we look into our crystal ball, what we see as a requirement for this and future IGCC units to become a success is a unit with performance, as follows:

Polk Unit #1

Capacity	-	250MW
Capital Cost	-	\$500,000,000

C.O. Date - July - October 1996
Heat Rate - 8700 Btu/Kwh
Emissions - equal to permit limits
Acceptance from our neighbors

Future IGCC Units

Capacity - 260+MW
Heat Rate - ≤ 8400 Btu/Kwh
Capital Cost - \$1,500/Kw (without DOE support)
Improved Emissions (below NSPS)
Mass production (lower costs)

It appears that most of the immediate applications for IGCC are being focused in the European sector and the Pacific Rim (China and Indonesia). Most developers are either actively involved in proposals for these areas or are watching the markets to be prepared for entry into these markets as they develop.

As far as U. S. applications, there continues to be considerable interest in IGCC installations for addressing the Phase II Clean Air Act Amendments requirements which take effect at the close of this century.

We feel that the Polk Power Station Unit #1 will provide needed input for all these and other future installations of IGCC technology.

THE TOMS CREEK CLEAN COAL IGCC DEMONSTRATION PROJECT

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Paper presented at the Third Annual Clean Coal Technology Conference
Chicago, IL, September 6-8, 1994

THE TOMS CREEK CLEAN COAL IGCC DEMONSTRATION PROJECT

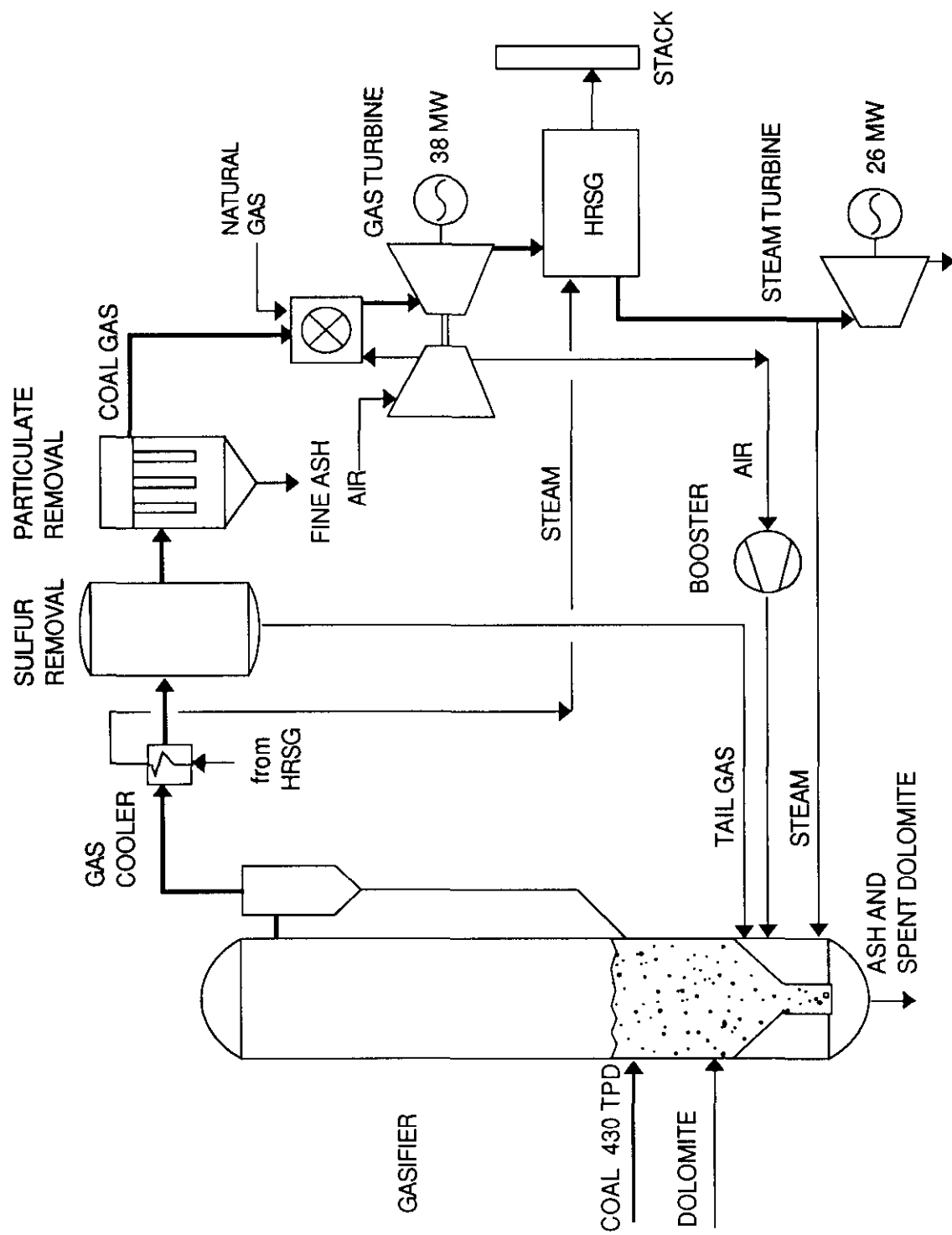
INTRODUCTION

On October 20, 1992 the US Department of Energy (DOE), through the Morgantown Energy Technology Center, entered into Cooperative Agreement DE-FC-21-93MC92444 with TAMCO Power Partners to implement the Toms Creek IGCC (Integrated Gasification Combined-Cycle) Demonstration Project.

The process design is complete and a draft Environmental Information Volume has been produced for the Toms Creek site. The overall project schedule has slipped and the first budget period has been extended by seven months because a power purchase agreement has yet to be negotiated.

TECHNOLOGY OVERVIEW

A diagram of the Toms Creek process is shown in Figure 1. Coal gas is produced in an air-blown fluidized bed gasifier using IGT's U-GAS® technology. The calcium in the dolomite, which is fed to the gasifier at a 2-to-1 stoichiometric ratio, captures most of the sulfur from the coal. The balance of the sulfur, and the particulate matter elutriated from the gasifier by the coal gas, are removed by the hot gas clean-up system which is located between the gasifier and the gas turbine generator. Electrical power is generated from the combustion of the clean hot coal gas in a gas turbine generator. Power is also generated from the steam produced in a heat recovery steam generator by cooling the hot combustion gases coming from the gas turbine generator. Air for the gasifier is extracted from the gas turbine air compressor.



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Figure 1. Toms Creek Process Diagram

When coal gas is unavailable, power generation will be maintained by firing the gas turbine generator with natural gas.

The contaminants in the exhaust gases leaving the heat recovery steam generator are within New Source Performance Standards. The ash and spent dolomite discharged from the gasifier have been shown to be environmentally benign. Cooling tower and boiler blow-down streams comprise the only aqueous discharge from the plant.

PROJECT OVERVIEW

Project Goals

The goal of the Project is to demonstrate the environmentally acceptable operation of an IGCC system in a commercial setting.

TAMCO will undertake this demonstration. Based on IGT's U-GAS® technologies, the demonstration includes all major sub-systems: coal feeding; a pressurized, air-blown, fluidized bed gasifier capable of utilizing high sulfur bituminous coal; a gas conditioning system for removing sulfur compounds and particulates from the coal gas at elevated temperatures; an advanced combustion turbine capable of switching "on the fly" between the low Btu coal gas and natural gas; the steam cycle, including a heat recovery steam generator and steam turbine generator; all control systems; and the balance of the plant.

Project Participants

The Toms Creek Project organization is shown in Figure 2. TAMCO Power Partners was organized to provide a rational means for two large, diverse US companies (Tampella Power Corporation and Coastal Power Production Company) to demonstrate, with substantial Government support, the commercial viability of the IGT U-GAS® technology in an IGCC configuration. Each partner owns fifty percent of TAMCO. Together the partners will invest

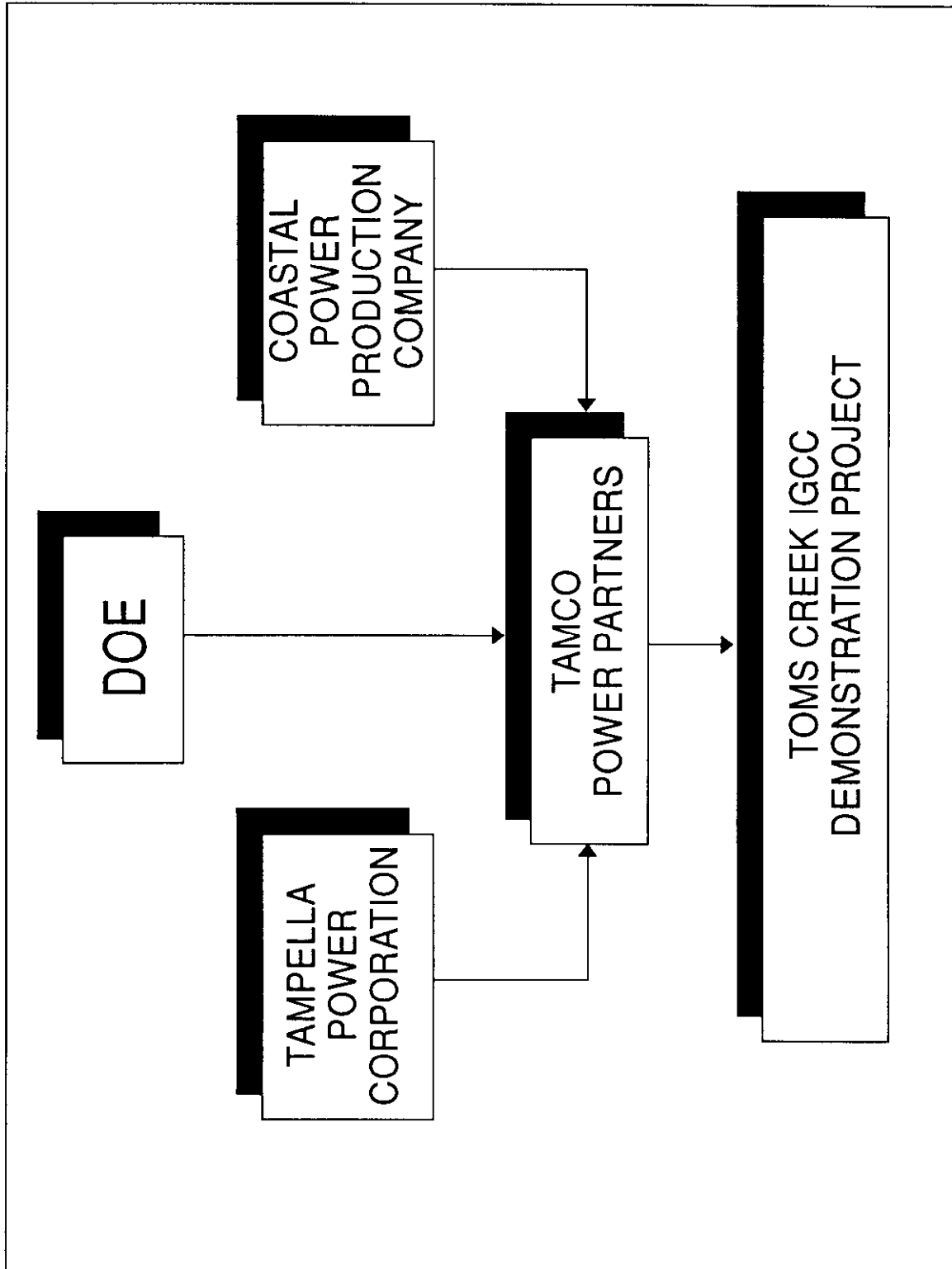


Figure 2. Toms Creek Project Team

more than half of the estimated \$196.6 million total project cost. The Government will share 48.3% of the costs, up to a maximum of \$95.0 million.

U-GAS® TECHNOLOGY

U-GAS® technology is centered about a pressurized fluidized bed coal gasification process which produces a low to medium Btu fuel gas from a variety of feedstocks including highly caking, high sulfur, and high ash coals. A simplified diagram of the U-GAS® gasifier is shown in Figure 3.

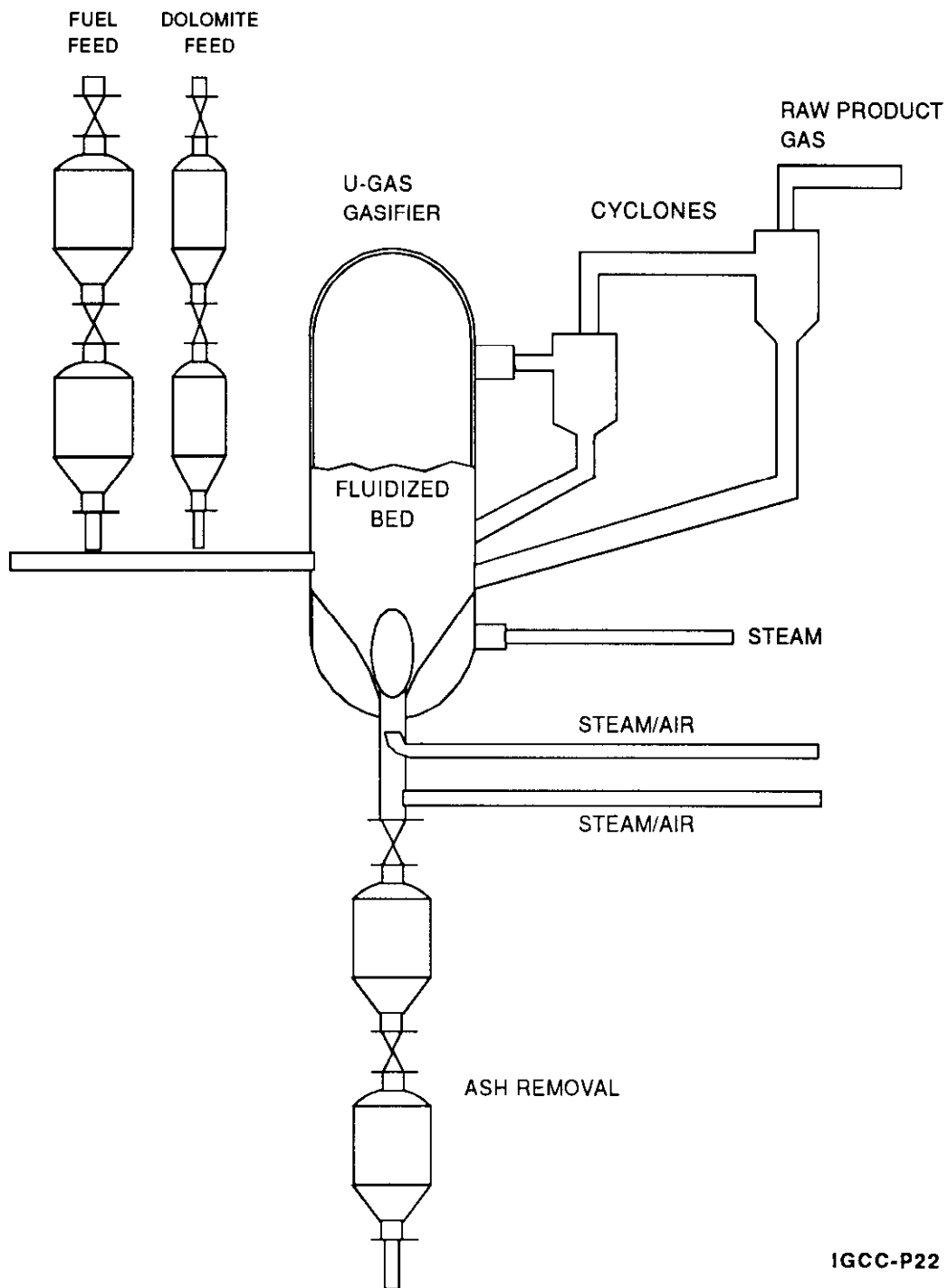
Coal Preparation and Feeding

The incoming coal is sized to minus 1/4 inch, plus zero, and dried to a point where surface moisture does not present a handling problem, typically 5% at Toms Creek. Both the coal and dolomite feed systems contain a set of lock hoppers through which the solids are pressurized, and from which they are transported pneumatically to the gasifier.

Gasification

Coal is pyrolyzed, devolatilized, and gasified in a fluidizing medium of air and steam. The bed temperature ranges between 1,650 and 1,900 F. The pressure in the gasifier, typically 320 psig, is determined by the pressure drop through the hot gas clean-up systems and the requirements of the gas turbine generator. The temperature within the bed depends on the type of coal and is controlled to maintain non-slagging conditions for the ash. Coal is gasified rapidly, producing a mixture of carbon monoxide, carbon dioxide, methane, hydrogen, water vapor, and about 50% nitrogen; in addition, small quantities of hydrogen sulfide, ammonia, and other trace impurities are produced. In the reducing environment of the gasifier nearly all of the sulfur present in the coal is converted to hydrogen sulfide before it reacts with the calcium in the dolomite.

U-GAS GASIFIER



IGCC-P22

Figure 3. The U-GAS Process Gasifier

Fluidizing gas is introduced into the reactor through the gas distributor plate and through the ash discharge device. In the U-GAS® process, operating conditions in the oxidizing zone are controlled to achieve a low carbon loss which enables 97+% overall carbon conversion. The fines swept from the gasifier may be separated from the product gas in two stages of cyclones and returned to the fluidized bed. The product gas is virtually free of tars and oils, in large part, due to the relatively high temperature in the upper stage of the gasifier.

HOT GAS CONTAMINANTS

Sulfur

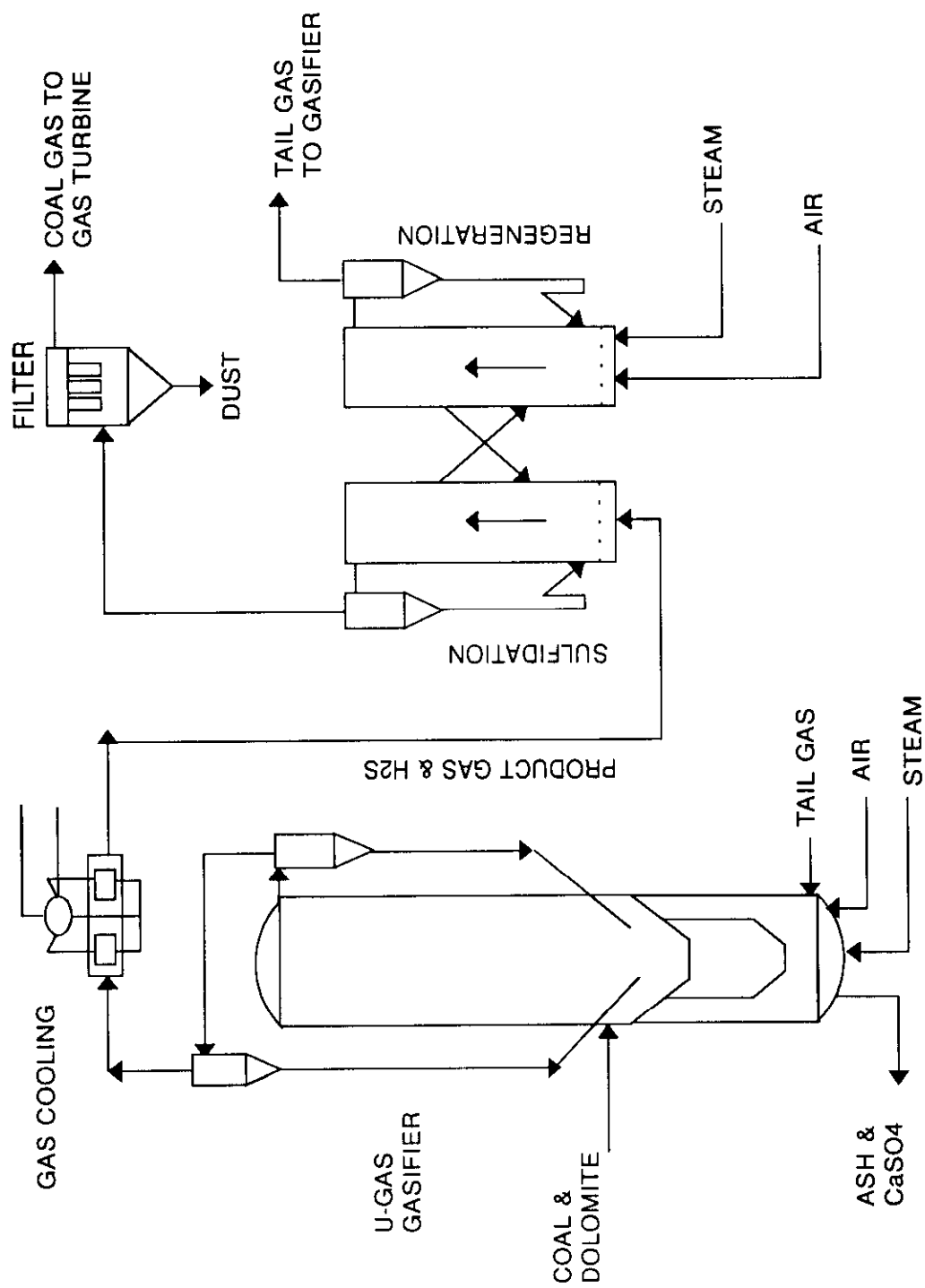
As shown in Figure 4, desulfurization is accomplished in two stages.

The bulk of sulfur is removed in the gasifier by an equilibrium reaction with the calcium in the dolomite. First, the hydrogen sulfide reacts to form calcium sulfide. Then, in the lower portion of the gasifier, the calcium sulfide is oxidized to calcium sulfate. The bottoms product from the gasifier is further stabilized by maintaining the temperature in the lower part of the bed near the fusion temperature of the ash so that controlled particle growth occurs while the particle surfaces acquire a vitreous coating.

The balance of the sulfur is removed from the coal gas in the hot gas clean-up system. Tampella Power has developed a two fluidized-bed reactor system. Hot coal gas is contacted with Zn/Ti sorbent in the first reactor, where the sulfur is captured by zinc oxide. Sulfided sorbent is regenerated in the second reactor with air and steam. The tail gas from the regenerator is recycled to the gasifier where the sulfur dioxide is captured by the dolomite.

Very recent pilot plant tests, which incorporated this sulfur polishing system, yielded very encouraging results.

SULFUR REMOVAL IN THE IGCC PROCESS



IGCC-P23

Figure 4. Hot Gas Clean-Up

Nitrogen Compounds

The nitrogen in the coal forms ammonia, some hydrogen cyanide, and small amounts of other volatile nitrogen compounds during gasification. To reduce the conversion of ammonia to NO_x in the gas turbine combustors, turbine manufacturers are developing staged combustion processes. The incorporation of a selective catalytic reaction system downstream of the gas turbine to meet NO_x emissions limits may not be necessary.

Alkali Metals

Volatile compounds of sodium and potassium which are formed in the gasifier, can participate in hot corrosion and lead to solids build-up in the gas turbine. In Tampella Power's IGCC process, the product gas is cooled to 1,020 F, which is below the dew point of the alkali compounds. As they cool to this temperature, the alkali vapors will condense on the particles that are intercepted by the candle filter.

Particulate Removal

To protect the gas turbine generator from particulate damage, and to meet air emissions limits, a ceramic barrier filter is used upstream of the turbine inlet valve. Most of the solids from the gasifier are captured by the cyclones. The ceramic filter collects the particulate material leaving the external desulfurizer, preventing it from reaching the gas turbine or the atmosphere. The ultimate disposition of the material trapped by the filter will be determined following its characterization during site-specific pilot plant testing.

Greenhouse Gases

The greenhouse gases of concern are carbon dioxide, methane, and nitrous oxide. In the IGCC process, the methane which is produced during gasification is burned in the combustor of the gas turbine. Nitrous oxide does not form in the reducing atmosphere of the gasifier, and its formation is not expected at the high temperatures encountered in the gas turbine combustor. The

emission of carbon dioxide cannot be avoided. Carbon dioxide emissions are reduced as a result of the improved efficiency of IGCC processes over simple combustion-based power generation.

THE DEVELOPMENT OF THE TAMPELLA IGCC PROCESS

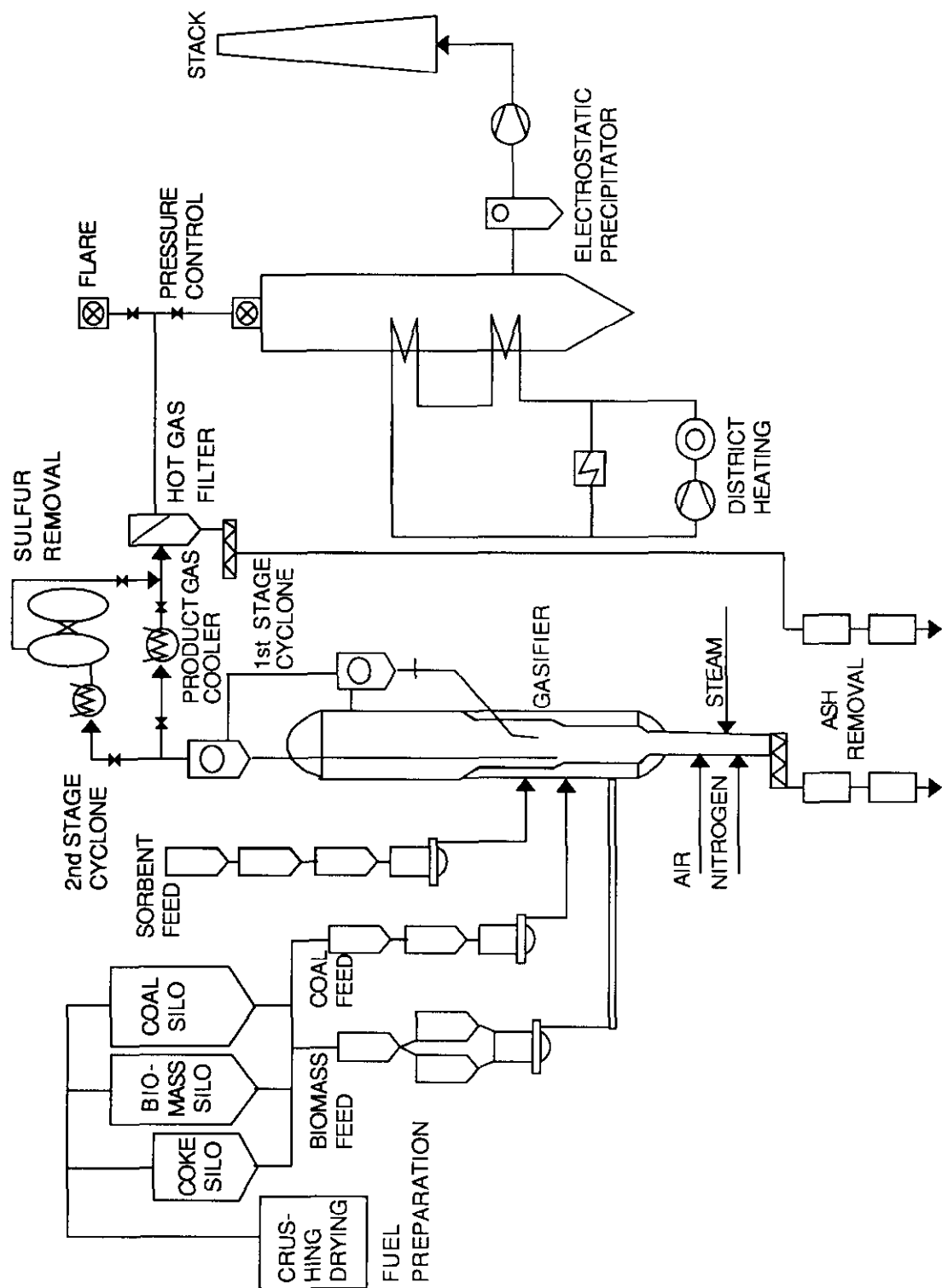
The Toms Creek IGCC Project utilizes a hot gas clean-up system to remove residual sulfur compounds and particulate matter from the gasifier product gas. Under license, and with the technical support of IGT, an integrated pilot plant was built by Tampella in Finland. The pilot is diagrammed in Figure 5, and an elevation sketch is shown in Figure 6. Following more than 1,000 operating hours, the plant was modified to incorporate the external desulfurization system discussed above. The data generated from this 15 MW (t) pilot plant have been used to confirm the theoretical design of the 140 MW (t) demonstration plant at Toms Creek. The pilot plant was operated for 1,000+ hours gasifying coal. Following a subsequent 1,000 hour biomass gasification campaign, the external desulfurization system was added. Testing conducted this spring was quite successful.

Environmental Performance

The Toms Creek plant does not produce any process waste water streams. Cooling water and boiler blow-downs are the only aqueous discharges.

The only solid waste from the plant is a mixture of ash, spent dolomite and calcium sulfate which is discharged from the of the gasifier and the filter. Preliminary tests have shown this material to be a non-hazardous waste which could be utilized in road construction or disposed of in a landfill. Initially, the glassified product will be placed in the adjacent coal refuse valley, which is part of the coal preparation facility operation.

Air emissions from the plant are anticipated to be well below current requirements: SO₂ emission of 0.056 lb/MMBtu, NO_x emission of 0.24 lb/MMBtu, and particulate PM₁₀ emission of 0.016 lb/MMBtu.

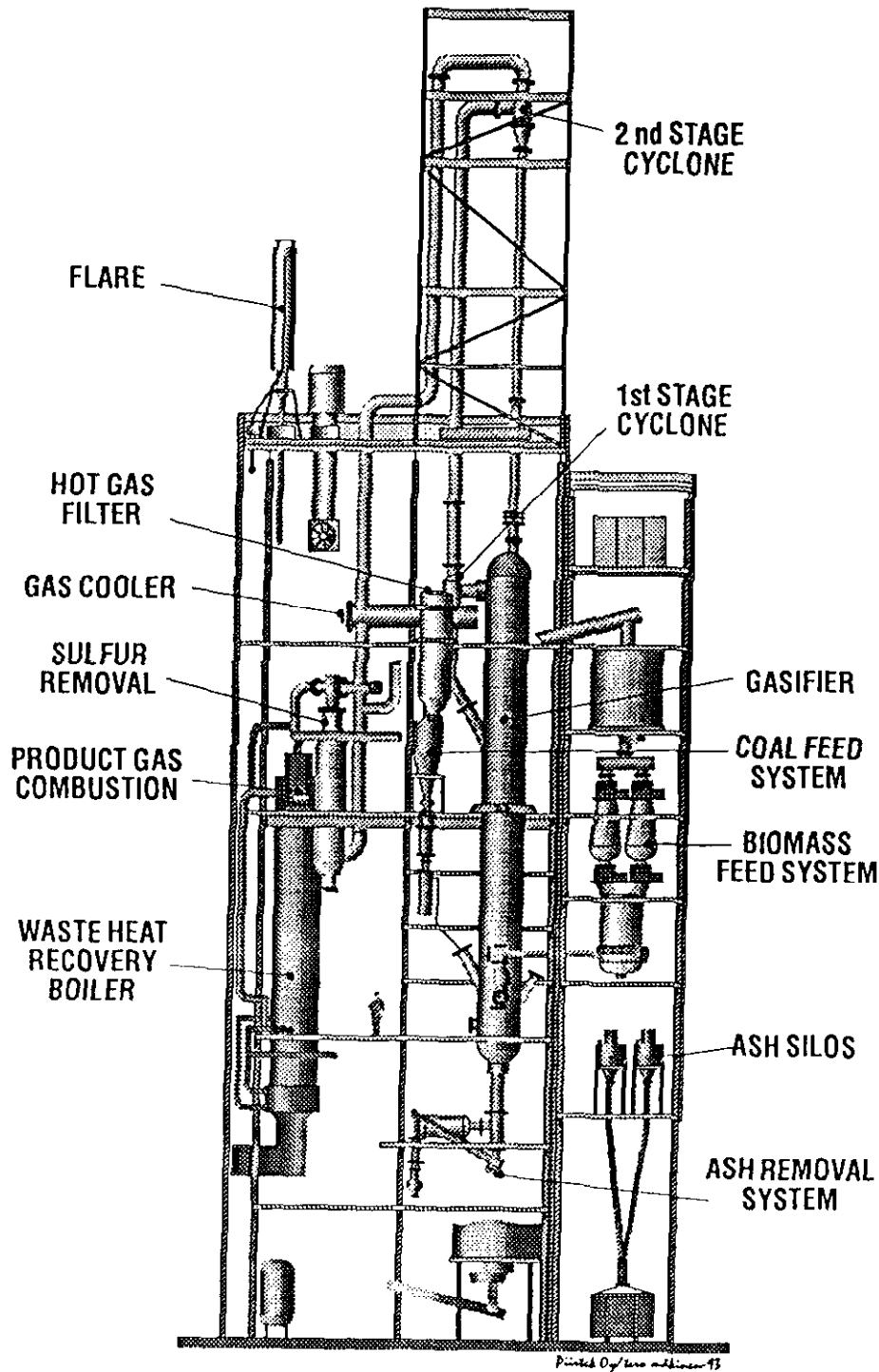


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Figure 5. Pilot Plant Schematic Diagram

ENVIROPOWER PRESSURIZED GASIFICATION PILOT PLANT

TAMPERE, FINLAND 15 MW, 30 bar



ENVIROPOWER
TAMPELLA POWER & VATTENFALL ENGINEERING

Figure 6. Elevation sketch

Status

An Environmental Impact Volume was drafted and on-going support is being given to the NEPA process. Process design studies specific to the Toms Creek site have been completed. Preliminary calculations for alternate sites are being made on an ad hoc basis. As yet, there is no power sales agreement.

Schedule

A revised schedule, reflecting adjustments made to the timing of the Design Phase, is given in Figure 7.

TOMS CREEK IGCC DEMONSTRATION PROJECT
Revised Schedule

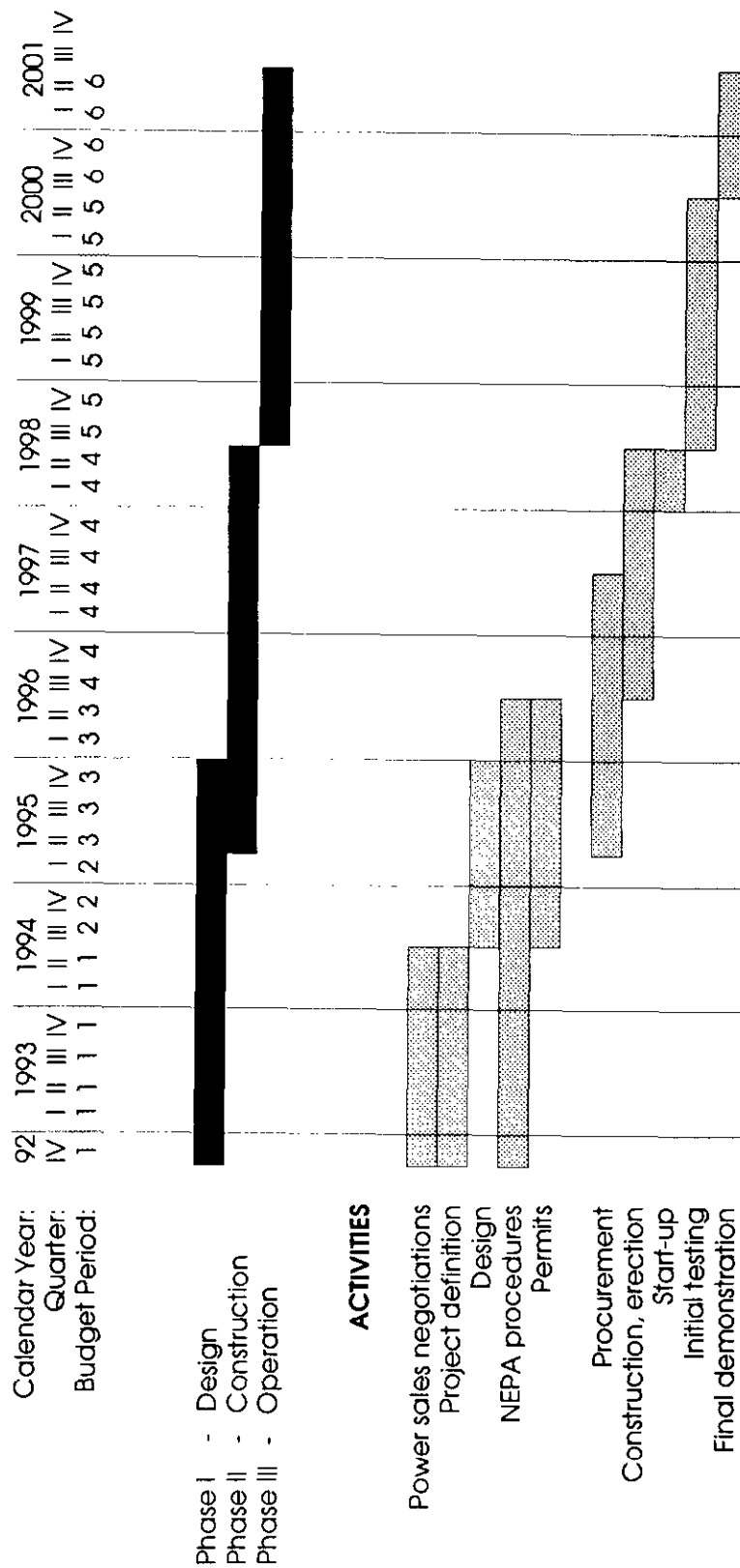


Figure 7. Toms Creek Project Schedule

MODSCHED.wk3

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3. Risto Hokajarvi, Kari Salo, "Development of New Generation IGCC", Eleventh Annual International Pittsburgh Coal Conference (1994).

**Application of British Gas/Lurgi Gasification Process
in the U.S. DOE Clean Coal Technology Program - Round Five**

Kenneth S. Johnson, Duke Energy

Abstract

The selection of Duke Energy's proposal under DOE's Clean Coal Technology Program - Round Five (CCT-V) for a 484-MWe coal gasification combined cycle (CGCC) power station provides an opportunity for full-scale commercial demonstration of the British Gas/Lurgi (BGL) Gasifier in advanced power generation. The highly efficient conversion of coal to clean fuel gas in the BGL gasification process coupled with today's advanced combustion turbines significantly improves the thermal performance of coal utilization. In addition, coal conversion allows the application of highly effective gas cleaning processes, which are routinely used in the petrochemical industry. These cleaning processes remove pollutants prior to combustion enabling environmental impacts to be dramatically reduced relative to conventional coal-based power generation technologies which use back-end pollution control equipment. Duke Energy is coordinating and managing the team which is developing an advanced CGCC plant. A status of the project, along with the design features and plant performance, are discussed in the paper.

The Healy Clean Coal Project

Rick Gleiser
Joy Technologies

Abstract

The Healy Clean Coal Project involves the permitting, design, construction, operation, and testing of a new 50 MWe nominal pulverized coal-fired power plant. The plant features the innovative integration of TRW's slagging system with Joy's advanced flue gas desulfurization system. The integration of these technologies is expected to cost effectively result in low emissions of NO_x and SO_x. This paper will present a description of the technologies and the status of the project.

TECHNICAL SESSION 5:

**COAL COMBUSTION/
COAL PROCESSING**

Co-Chairs:

Timothy S. McIlvried

Pittsburgh Energy Technology Center
U.S. Department of Energy

Douglas M. Jewell

Morgantown Energy Technology Center
U.S. Department of Energy

500 MW DEMONSTRATION OF ADVANCED WALL-FIRED COMBUSTION TECHNIQUES FOR THE REDUCTION OF NITROGEN OXIDE EMISSIONS FROM COAL-FIRED BOILERS

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Southern Company Services, Inc.
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Birmingham, Alabama 35202

ABSTRACT

This paper discusses the technical progress of a U. S. Department of Energy Innovative Clean Coal Technology project demonstrating advanced wall-fired combustion techniques for the reduction of nitrogen oxide (NO_x) emissions from coal-fired boilers. The primary objective of the demonstration is to determine the long-term NO_x reduction performance of advanced overfire air (AOFA), low NO_x burners (LNB), and advanced digital control/optimization methodologies applied in a stepwise fashion to a 500 MW boiler. The focus of this paper is to (1) present final results from the AOFA, LNB, and LNB+AOFA test phases and (2) provide an overview of the advanced digital control/optimization methods scheduled for demonstration starting fall 1994. Results from various LNB and AOFA testing and optimization efforts over a four year period provided a progressive improvement in emissions performance as operating and technical familiarity increased.

TABLE OF ABBREVIATIONS

AOFA	Advanced Overfire Air
ASME	American Society of Mechanical Engineers
C	carbon
CF/SF	Controlled Flow/Split Flame
Cl	chlorine
CO	carbon monoxide
DAS	data acquisition system
DOE	United States Department of Energy
ECEM	extractive continuous emissions monitor
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
F	Fahrenheit
FC	fixed carbon
FWEC	Foster Wheeler Energy Corporation
H	hydrogen
HHV	higher heating value
ICCT	Innovative Clean Coal Technology
lb(s)	pound(s)
LNB	low NO _x burner
LOI	loss on ignition
(M)Btu	(million) British thermal unit
MW	megawatt
N	nitrogen
NO _x	nitrogen oxides
NSPS	New Source Performance Standards
O, O ₂	oxygen
psig	pounds per square inch gauge
PTC	Performance Test Codes
RSD	relative standard deviation
S	sulfur
SCS	Southern Company Services
SO ₂	sulfur dioxide
UARG	Utility Air Regulatory Group
VM	volatile matter

INTRODUCTION

This paper discusses the technical progress of one of the U. S. Department of Energy's Innovative Clean Coal Technology (ICCT) projects demonstrating advanced combustion techniques for the reduction of nitrogen oxide (NO_x) emissions from wall-fired boilers. This demonstration is being conducted on Georgia Power Company's Plant Hammond Unit 4, a 500 MW, pre-NSPS (New Source Performance Standards), wall-fired boiler. Plant Hammond is located near Rome, Georgia, northwest of Atlanta.

This project is being managed by Southern Company Services, Inc. (SCS) on behalf of the project co-funders: The Southern Company, the U. S. Department of Energy (DOE), and the Electric Power Research Institute (EPRI). In addition to SCS, Southern includes the five electric operating companies: Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Savannah Electric and Power. SCS provides engineering and research services to the Southern electric system. The ICCT program is a jointly funded effort between DOE and industry to move the most promising advanced coal-based technologies to the commercial marketplace. The goal of ICCT projects is the demonstration of commercially feasible, advanced coal-based technologies that have already reached the "proof-of-concept" stage. The ICCT projects are jointly funded endeavors between the government and the private sector in which the industrial participant contributes at least 50 percent of the total project cost. The DOE is participating through the Office of Clean Coal Technology at the Pittsburgh Energy Technology Center (PETC).

The primary objective of the demonstration is to determine the long-term NO_x reduction performance of advanced overfire air (AOFA), low NO_x burners (LNB), and advanced digital control/optimization methodologies applied in a stepwise fashion to a 500 MW boiler. Short-term tests of each technology are also being performed to provide engineering information about emissions and performance trends [1,2,3].

Following a brief unit and technology review, this paper (1) presents the final results from the AOFA, LNB, and LNB+AOFA test phases and (2) provides an overview of the advanced digital control/optimization methods scheduled for demonstration starting fall 1994.

UNIT AND TECHNOLOGY REVIEW

Georgia Power Company's Plant Hammond Unit 4 is a Foster Wheeler Energy Corporation (FWEC) opposed wall-fired boiler, rated at 500 MW gross, with design steam conditions of 2500 psig and 1000/1000°F superheat/reheat temperatures, respectively. The unit was placed into commercial operation on December 14, 1970. Prior to the LNB retrofit in 1991, six FWEC Planetary Roller and Table type mills provided pulverized eastern bituminous coal (12,900 Btu/lb, 33% VM, 53% FC, 72% C, 1.7% S, 1.4% N, 10% ash) to 24 pre-NSPS, Intervane burners. The burners are arranged in a matrix of 12 burners (4W x 3H) on opposing walls with each mill supplying coal to four burners per elevation.

During a spring 1991 unit outage, the Intervane burners were replaced with FWEC Controlled Flow/Split Flame (CF/SF) burners. In the CF/SF burner, secondary combustion air is divided between inner and outer flow cylinders (Figure 1). A sliding sleeve damper regulates the total

secondary air flow entering the burner and is used to balance the burner air flow distribution. An adjustable outer register assembly divides the burner's secondary air into two concentric paths and also imparts some swirl to the air streams. The secondary air that traverses the inner path, flows across an adjustable inner register assembly that, by providing a variable pressure drop, apportions the flow between the inner and outer flow paths. The inner register also controls the degree of additional swirl imparted to the coal/air mixture in the near throat region. The outer air flow enters the furnace axially, providing the remaining air necessary to complete combustion. An axially movable inner sleeve tip provides a means for varying the primary air velocity while maintaining a constant primary flow. The split flame nozzle segregates the coal/air mixture into four concentrated streams, each of which forms an individual flame when entering the furnace. This segregation minimizes mixing between the coal and the primary air, assisting in the staged combustion process.

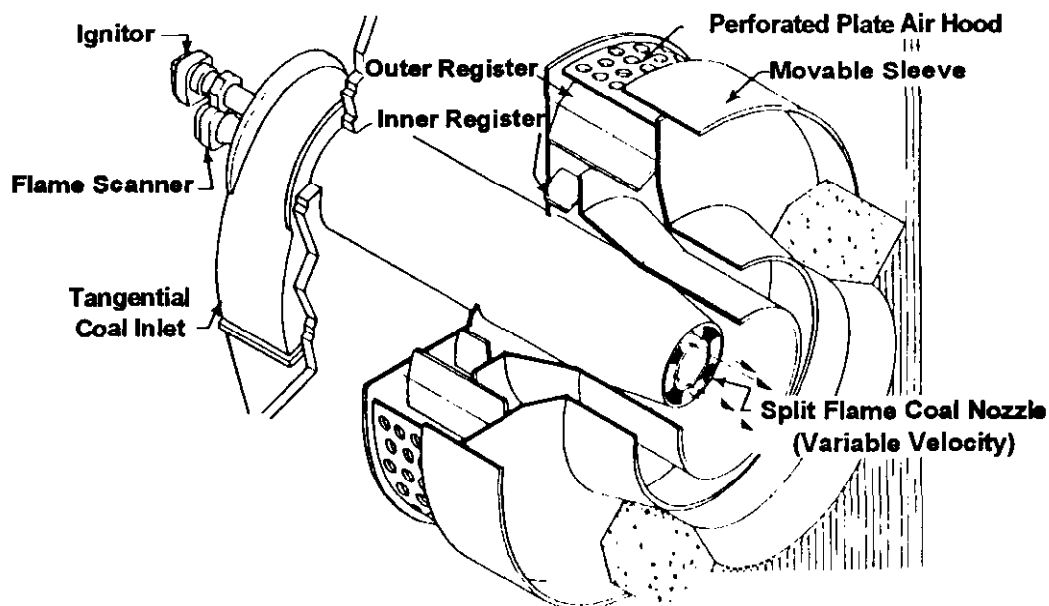
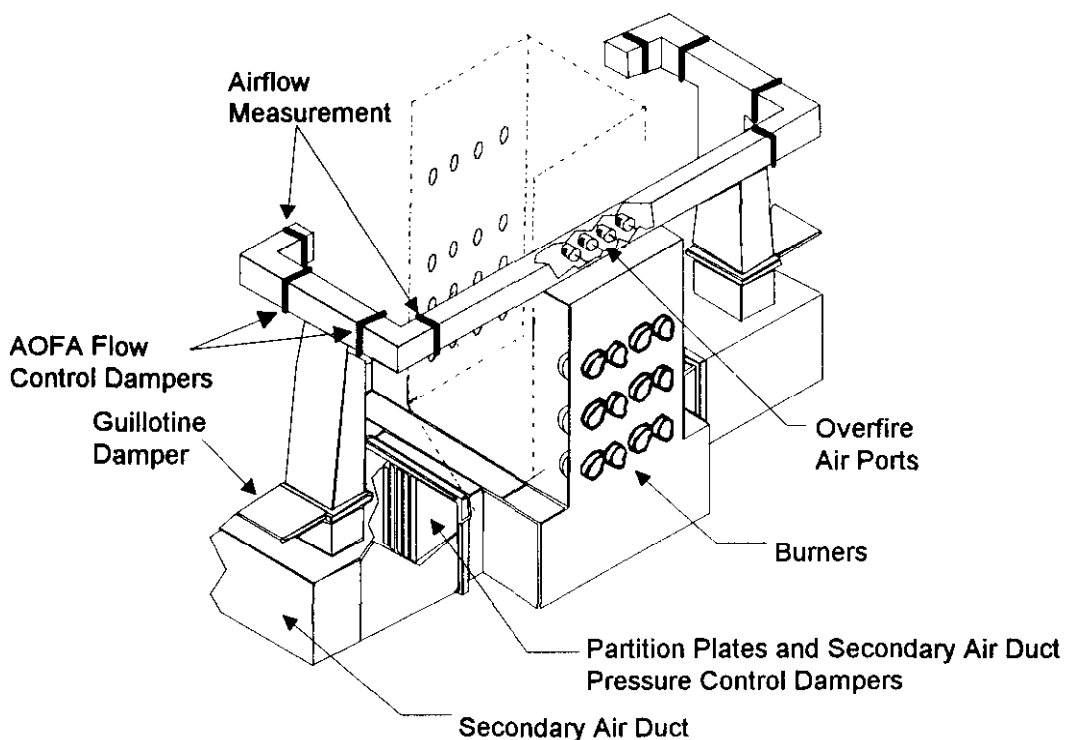


Figure 1. FWEC CF/SF Low NO_x Burner

As part of this demonstration project, the unit was also retrofit with an Advanced Overfire Air (AOFA) system (Figure 2). The FWEC design diverts air from the secondary air ductwork and incorporates four flow control dampers at the corners of the overfire air windbox and four overfire air ports on both the front and rear furnace walls. Due to budgetary and physical constraints, FWEC designed an eight port AOFA system more suitable to the project and unit than the twelve port system originally proposed.

The Unit 4 boiler was designed for pressurized furnace operation but was converted to balanced draft operation in 1977. The unit is equipped with a coldside ESP and utilizes two regenerative secondary air preheaters and two regenerative primary air heaters. During the course of the ICCT demonstration, the unit was retrofitted with four Babcock & Wilcox MPS 75 mills (two each during the spring 1991 and spring 1992 outages).



REVIEW OF PRIOR TESTING

Baseline, AOFA, LNB, and LNB+AOFA test phases have been completed (Table 1). Short-term and long-term baseline testing was conducted in an "as-found" condition from November 1989 through March 1990. Following retrofit of the AOFA system during a four-week outage in spring 1990, the AOFA configuration was tested from August 1990 through March 1991. The FWEC CF/SF low NO_x burners were then installed during a seven week outage starting on March 8, 1991 and continuing to May 5, 1991. Following optimization of the LNBs and ancillary combustion equipment by FWEC personnel, LNB testing was commenced during July 1991. However, due to significant post-LNB increases in precipitator fly ash loading and gas flow rate and also, increases in fly ash LOI which adversely impacted stack particulate emissions, the unit was run below 300 MW from September to November 1991 [4]. Following installation of an ammonia flue gas conditioning system, the unit was able to return to full load operation and complete the LNB test phase during January 1992.

Phase	Description	Date	Status
0	Pre-Award Negotiations		
1	Baseline Characterization	8/89 - 4/90	<i>Completed</i>
2	Advanced Overfire Air Retrofit (AOFA) & Characterization	4/90 - 3/91	<i>Completed</i>
3A	Low NO _x Burner Retrofit (LNB) & Characterization	3/91 - 1/92	<i>Completed</i>
3B	LNB+AOFA Characterization	1/92 - 8/93	<i>Completed</i>
4	Digital Controls/Optimization Retrofit & Characterization	9/93 - 4/95	<i>In Progress</i>
5	Final Reporting and Disposition	5/95 - 12/95	<i>Later</i>

Table 1. Project Schedule

Given the extended LNB test phase, insufficient time was available to complete the full requirements of the LNB+AOFA test phase prior to the spring 1992 outage; therefore it was decided to collect abbreviated data prior to this outage and comprehensive data following the outage. Following the outage, it was found that the AOFA had exacerbated the stack particulate emissions and the unit was again load limited, this time to 450 MW. While efforts were made to resume full load operation, special tests (i.e., NO_x vs. LOI) were performed and long-term data collected [3]. On March 30, 1993, Hammond Unit 4 resumed full load operation and comprehensive testing in the LNB+AOFA configuration began. Testing in the LNB+AOFA configuration was completed during August 1993.

LNB+AOFA CHARACTERIZATION

Following completion of the LNB test phase during January 1992, testing in the low NO_x burner and advanced overfire air configuration was to begin with completion scheduled for late March 1992. However, due to delays associated with increased stack particulate emissions following the LNB installation, testing in the LNB+AOFA configuration could not be completed prior to the spring 1992 outage during which two new mills were to be installed. To obtain operating data prior to this outage, abbreviated testing (designated 3B') in the LNB+AOFA configuration was performed during February and March 1992. Following the spring 1992 outage, the unit ran at reduced loads (less than 450 MW) until spring 1993 to maintain stack particulate compliance. During this period, long-term data were collected and the NO_x vs. LOI tests were performed.

Following resumption of full load operation on March 26, 1993, FWEC personnel re-optimized the unit starting March 30, 1993 and continuing through May 6, 1993. Subsequent to the re-optimization, comprehensive testing using LNB plus AOFA began and was completed August 25, 1993. As shown in Figures 3 and 4, full load NO_x emissions (from the performance tests) are approximately 0.43 lb/MBtu with corresponding fly ash loss-on-ignition (LOI) values of 8 percent. At low loads (300 MW), NO_x emissions and LOI are approximately 0.32 lb/MBtu and 5.5 percent, respectively. Also shown in Figures 3 and 4 are the results from the February-March 1992 testing in the same configuration. NO_x emissions for the more recent round of testing are considerably below the NO_x levels found in these earlier tests (see discussion below).

A total of 63 days of valid long-term NO_x emissions data were collected during the LNB+AOFA test phase (Figure 5). Based on this data set, the full load, long-term NO_x emissions are approximately 0.40 lb/MBtu, which is consistent with that found during the short-term performance testing (Figure 3). However, at 300 MW, long-term NO_x emissions are 0.38 lb/MBtu, 0.06 lb/MBtu higher than the short-term emissions at the same load with approximately the same excess air and AOFA flow rate. The cause of this disparity is unknown. Despite this difference, the short-term data is within the 90th percentile range of the long-term data. As with the short-term data, the long-term NO_x emissions obtained in the LNB+AOFA configuration during the May - August 1993 test period were significantly reduced over that obtained previously in this configuration.

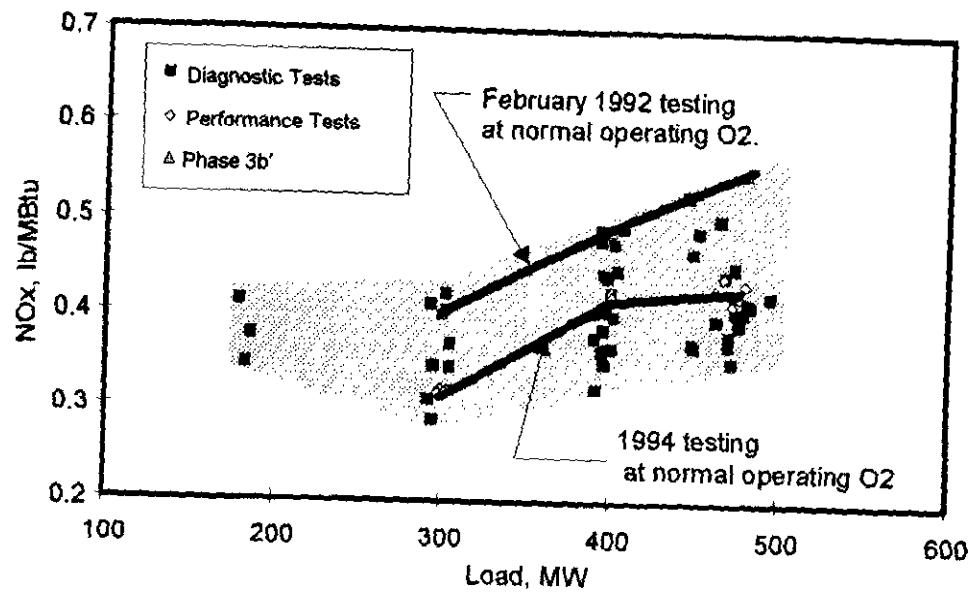


Figure 3. LNB+AOFA Short-Term NO_x Emissions

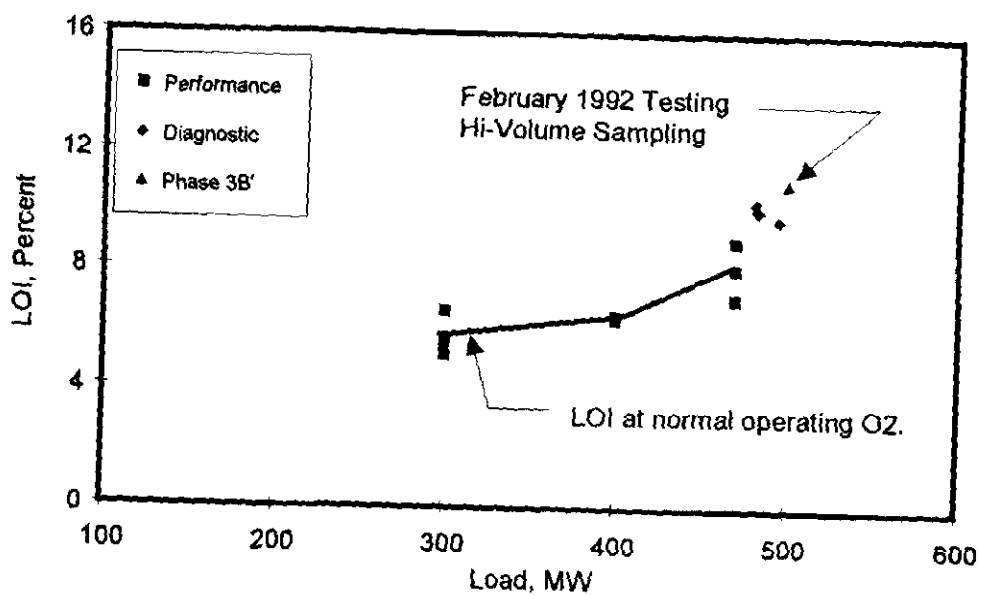


Figure 4. LNB+AOFA Short-Term Fly Ash Loss-on-Ignition

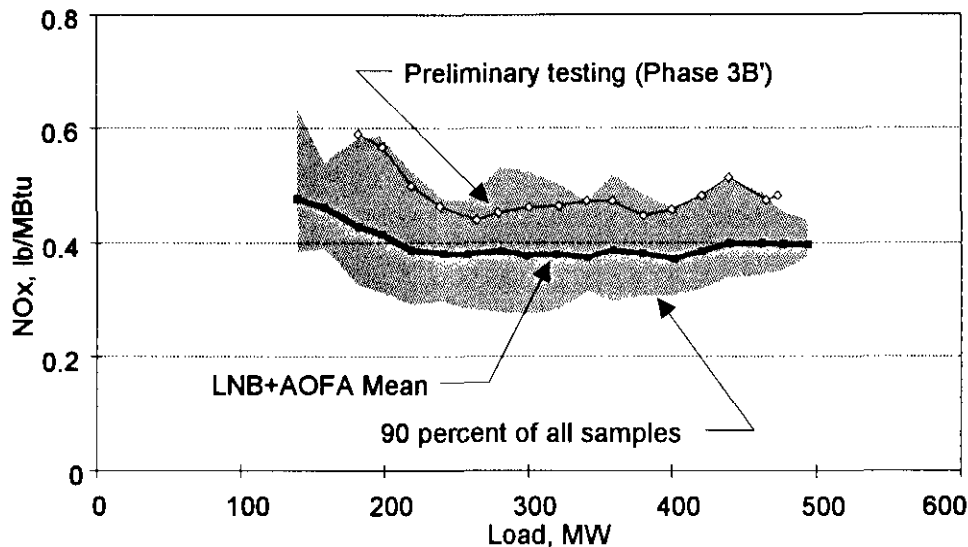


Figure 5. LNB+AOFA Long-Term NO_x Emissions

DATA COMPARISON

As previously discussed, baseline, AOFA, LNB, and LNB+AOFA test phases have been completed. The following paragraphs discuss the final NO_x and fly ash LOI results from these phases.

NO_x Reductions

Figure 6 compares the baseline, AOFA, LNB, and LNB+AOFA long-term NO_x emissions data for Hammond Unit 4. Baseline testing was performed in an "as-found" condition and the unit was not tuned for NO_x emissions for this test phase. For the AOFA, LNB, and LNB+AOFA test phases, following optimization of the unit by FWEC personnel, the unit was operated according to FWEC instructions provided in the design manuals. As shown, the AOFA, LNBs, and LNB+AOFA provide a long-term, *full load*, NO_x reduction of 24, 48, and 68 percent, respectively. The *load-weighted* average of NO_x emissions reductions was 14, 48, and 63 percent, respectively, for AOFA, LNBs, and LNB+AOFA test phases.

The *time-weighted* average of NO_x emissions for the baseline, AOFA, LNB, LNB+AOFA test phases are shown in Table 2. Since NO_x emissions are generally dependent on unit load, the NO_x values shown in this table are influenced by the load dispatch of the unit during the corresponding test frame. Also shown in this table are the 30 day and annual achievable emission limits (AEL) as determined during these test periods. The 30-day rolling average AEL is defined as the value that will be exceeded, on average, no more than one time per ten years. For the annual average, a compliance level of 95 percent was used in the calculation.

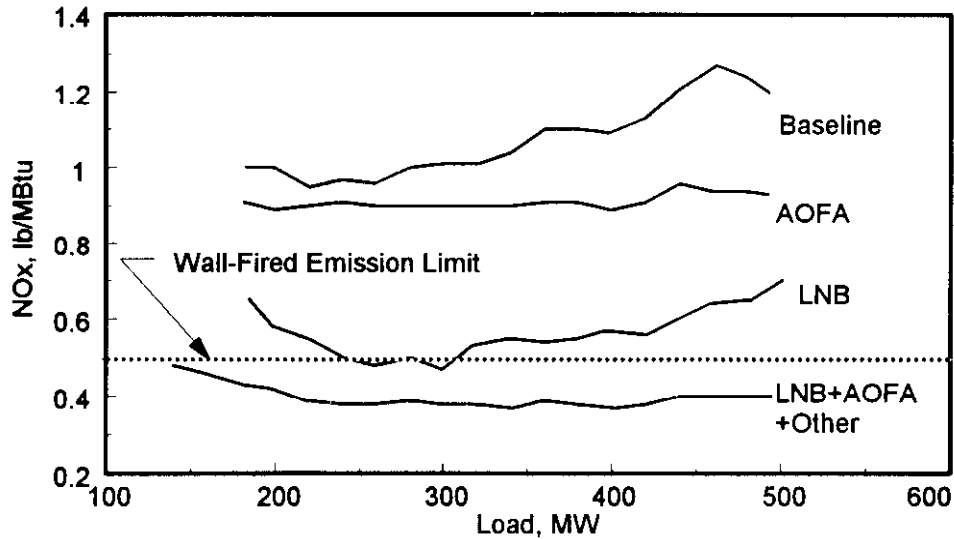


Figure 6. Long-Term NO_x Emissions vs. Load Characteristic

Unit Configuration →	Baseline		AOFA		LNB		LNB+AOFA	
Parameter ↓	Mean	RSD,%	Mean	RSD,%	Mean	RSD,%	Mean	RSD,%
Number of Daily Avg. Values	52	-	86	-	94	-	63	-
Load (MW)	407	9.4	386	17.9	305	17.7	293	23.9
NO _x Emissions (lb/MBtu)	1.12	9.5	0.92	8.6	0.53	13.7	0.41	12.9
O ₂ Level (percent at stack)	5.8	11.7	7.3	12.6	8.4	7.7	8.73	16.3
NO _x 30 Day AEL (lb/MBtu)	1.24	-	1.03	-	0.64	-	0.51	-
NO _x Annual AEL (lb MBtu)	1.13	-	0.93	-	0.55	-	0.42	-

Table 2. Long-Term NO_x Emissions

Fly Ash Loss-On-Ignition

The fly ash loss-on-ignition (LOI) values increased significantly for the AOFA and LNB test phases and similar increases have been experienced in the LNB+AOFA testing (Figure 7). These LOI increases were evident over the load range. The LOI measurements were made during each performance test using fly ash collected by EPA's Method 17 at the secondary air heater outlet [5]. The NO_x emissions from the performance tests are also shown in the same figure. As shown in Table 3, mill performance was generally better in the AOFA, LNB, and LNB+AOFA test phases than during baseline. The improvement in coal fineness was likely responsible for the reduction in fly ash LOI levels during the May-August 1993 LNB+AOFA test phase. Although it is commonly recognized that fuel fineness can have a pronounced effect on fly ash LOI, results from Plant Smith, Plant Gaston, and other sources indicate the direct impact of fuel fineness on NO_x emissions is small [6,7,8]. As previously reported, the post LNB retrofit increase in fly ash LOI along with increases in combustion air requirements and fly ash loading to the precipitator, has had an adverse impact on the unit's stack particulate emissions [4].

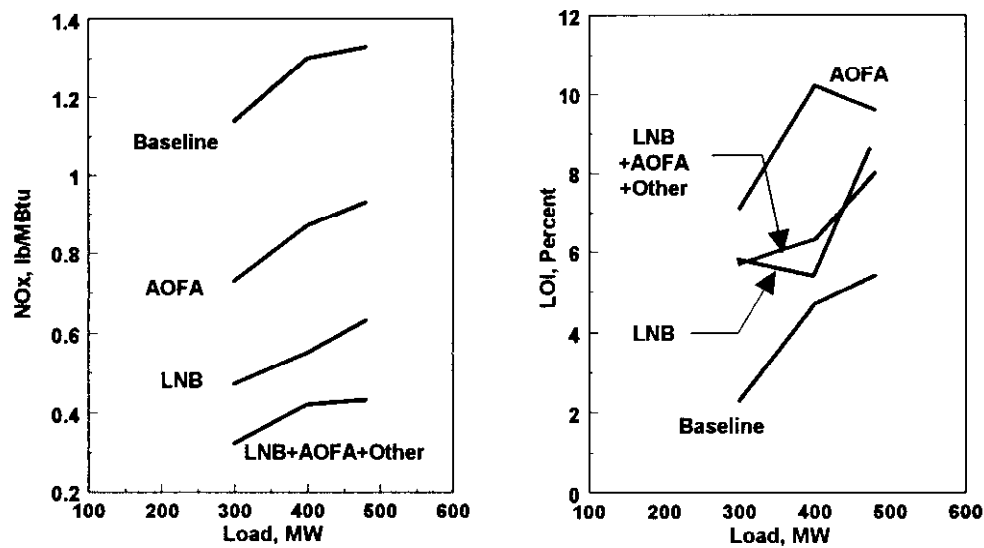


Figure 7. Performance Test Results

Technology	Coal Fineness	
	Passing 200 Mesh Percent	Remaining 50 Mesh Percent
Baseline	63	2.8
AOFA	67	2.6
LNB	67	1.4
LNB+AOFA	74	0.6

Table 3. Mill Performance Summary

LNB to LNB+AOFA NOx Reduction

As shown above, NOx emissions were reduced between the LNB and LNB+AOFA test phases. Factors contributing to this reduction are discussed below.

Performance of AOFA System

Figure 8 shows NOx emissions as a function of AOFA flow rate for the LNB+AOFA test phase. Using this curve to extrapolate to zero overfire air flow, the NOx emission level of the furnace without AOFA can be estimated. Using this procedure for the LNB+AOFA test phase, the effectiveness of the AOFA system when added to the LNBs was approximately 16 percent indicating that much of the incremental NOx reduction achieved was not the result of the AOFA system, but was the result of other factors. Also, the 16 percent incremental

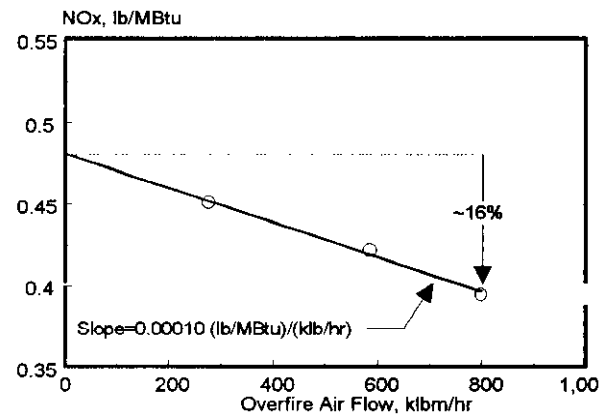


Figure 8. Effectiveness of AOFA System

NOx reduction effectiveness of AOFA is more in concordance with prior experience with this technology at this site and elsewhere.

Biasing of the Primary Coal and Air Flows

The results of the special NOx vs. LOI testing are shown in Figure 9 [3]. As shown, other than excess oxygen, mill biasing had more impact on NOx emissions than any of the other parameters tested. As determined from these tests, the most favorable mill bias configuration was with the upper mills positively biased (more coal flow than average) and the lower mills negatively biased (less coal flow than average). Figure 10 shows the mill loading for the LNB and LNB+AOFA test phases. During the LNB+AOFA test phase, mill biasing was in a NOx favorable configuration with the top mills having approximately 25 percent higher coal flow rates than the bottom mills. The mill bias was not as NOx favorable during the LNB test phase. Using the NOx vs. mill bias sensitivity, the NOx impact of this inadvertent bias can be estimated as being approximately 0.08 lb/MBtu.

Fuel Impacts

A comparison of the fuels burned during the LNB and LNB+AOFA test phases is shown in Table 4. Largely as the result of changes in the coal nitrogen and the fixed carbon to volatiles ratio, the difference in fuel quality may have resulted in a 0.04 lb/MBtu reduction in NOx emissions between the LNB and LNB+AOFA test phases.

Additional Combustion Tuning

Subsequent to the completion of the LNB test phase and preceding the comprehensive LNB+AOFA testing, FWEC personnel were on site 75 days conducting combustion optimization. The overall impact of this optimization on NOx emissions is difficult to quantify and may have had a neutral (or even adverse) impact on NOx emissions.

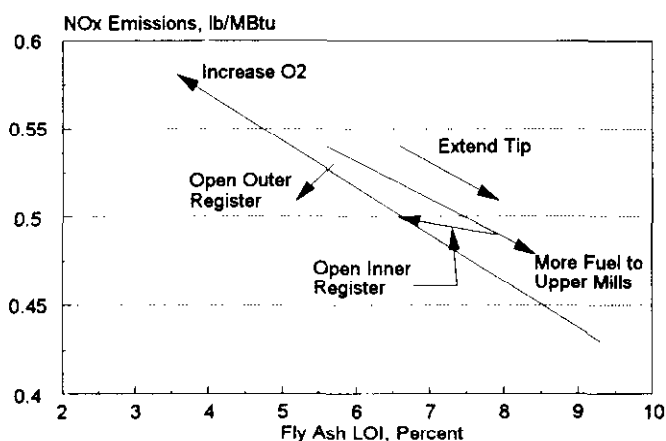


Figure 9. NOx vs. LOI Tests / All Sensitivities

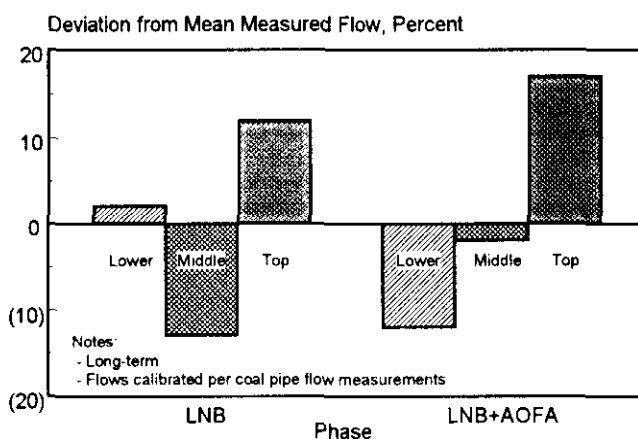


Figure 10. Mill Bias

	Units	Phase				
		1 Baseline	2 AOFA	3A LNB	3B' LNB+AOFA	3B LNB+AOFA
Moisture	%	4.28	5.60	5.69	5.51	6.42
Carbon	%	72.40	73.17	72.53	72.90	70.78
Hydrogen	%	4.69	4.72	4.67	4.68	4.66
Nitrogen	%	1.43	1.42	1.39	1.30	1.39
Sulfur	%	1.72	1.64	1.53	1.74	1.67
Ash	%	9.80	8.90	9.44	9.52	9.51
Oxygen	%	5.65	4.55	4.74	4.36	5.57
Total	%	99.97	100.00	99.99	100.01	100.00
HHV	Btu/lbm	12921	13000	12869	12919	12494
FC/Vol		1.57	1.57	1.61	1.65	1.50

Table 4 . Coal Comparison

A summary of the factors discussed above are shown in Table 5. As shown, the NOx emissions obtained during the LNB+AOFA phase can be accounted for by the factors shown in this table.

Phase		NOx Emissions	Resultant NOx Reduction* Percent	Comments
3A	LNB	0.65 lb/MBtu	47	Full-Load / Long-Term / As Tested
	+AOFA	0.54 lb/MBtu	9	16% Effectiveness
	+Biasing	0.46 lb/MBtu	7	10% Upper Mill Bias
	+Fuel	0.42 lb/MBtu	3	With 3B fuel
	+Tuning	?	?	Additional Tuning
	Total	0.42 lb/MBtu	66	Estimated Using Above Factors
3B	LNB+AOFA+Others	0.40 lb/MBtu	68	Full-Load / Long-Term / As Tested

*Relative to baseline

Table 5. NOx Accounting

ADVANCED CONTROLS AND OPTIMIZATION

The objective of this scope addition to the project at Plant Hammond is to evaluate and demonstrate the effectiveness of advance digital control/optimization methodologies as applied to the NOx abatement technologies installed at this site (LNB and AOFA). This scope addition will provide documented effectiveness of these control/optimization methods on NOx emissions and boiler efficiency improvements and guidelines for retrofitting boiler combustion controls for NOx emission reduction. The major task for this project addition include: (1) design and installation of a distributed digital control system (DCS), (2) instrumentation upgrades, (3) advanced controls/optimization design and implementation, and (4) characterization of the unit both before and after activation of the advanced strategies. Major milestones are shown in Table 6.

Milestone	Status
Digital control system design, configuration, and installation	Completed
Digital control system startup	Completed
Instrumentation upgrades	In Progress
Advanced controls/optimization design	In Progress
Characterization of the unit prior to activation of advanced strategies	Scheduled 8/94 - 10/94
Characterization of the unit following activation of advanced strategies	Scheduled 10/94 - 2/95

Table 6. Advanced Controls / Optimization Major Activities

The software and methodology to be demonstrated at Hammond is the *Generic NOx Control Intelligent System* (GNOCIS) whose development is being funded by a consortium consisting of the Electric Power Research Institute, PowerGen (a U.K. power producer), The Southern Company, U.K. Department of Trade and Industry, and U.S. Department of Energy [9]. The objective of the GNOCIS project is to develop an on-line enhancement to existing digital control systems that will result in reduced NOx emissions, while meeting other operational constraints on the unit (principally heat rate and other regulated emissions). The core of the system will be a model of the NOx generation characteristics of a boiler, that will reflect both short-term and longer-term shifts in boiler emission characteristics. The software will apply an optimizing procedure to identify the best set points for the plant. The recommended set points will be conveyed to the plant operators via the DCS or, at the plants discretion, the set points will be implemented automatically without operator intervention. The software will incorporate sensor validation techniques and be able to operate during plant transients (i.e. load ramping, fuel disturbances, and others). Figure 11 shows where GNOCIS fits with the rest of the digital control system.

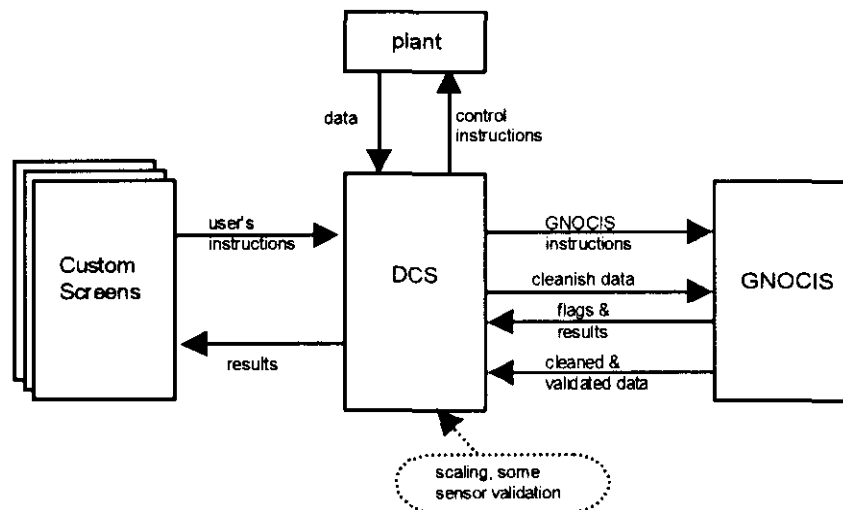


Figure 11. GNOCIS Functional Context

Following an initial feasibility study in which several promising methodologies were evaluated, a technique based on neural networks was selected to fulfill the “core” technology role in GNOCIS,

i.e. to form the basis of
Figure 12 shows a typical
Hammond 4 during the
normal unit operation.
parameters such as excess
and insurmountable pro
control/optimization str

conjunction with the LNBs provide approximately 15 to 20 percent additional NOx reduction benefit over LNB alone.

- For all low NOx combustion configurations, the unit experienced significant performance impacts including increases in excess air and fly ash LOI.
- At Hammond 4, operational and burner adjustments which favorably impacted NOx emissions adversely affected fly ash unburned carbon levels.
- Advanced digital control and optimization strategies have the potential to favorably impact NOx emission levels.

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**STATUS OF BABCOCK & WILCOX'S
CLEAN COAL TECHNOLOGY COMBUSTION MODIFICATION PROJECTS:
COAL REBURNING FOR CYCLONE BOILER NO_x CONTROL AND
LOW NO_x CELLTM BURNER DEMONSTRATIONS**

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**W.G. Maiden
Allegheny Power System**

ABSTRACT

Cyclone furnaces were developed by Babcock & Wilcox (B&W) to effectively combust low quality fuels. B&W's Cell burners were designed to maximize heat release in the boiler to improve efficiency. These objectives were readily achieved through intense combustion and resulting high temperatures; a condition generating disproportionately high levels of NO_x . Each technology represents approximately 13% of pre-New Source Performance Standards (NSPS) coal-fired generating capacity. B&W, co-sponsored by Electric Power Research Institute (EPRI), the host utilities and utility co-funding sponsors through U. S. Department of Energy (DOE) Clean Coal Technology Demonstration projects, addressed the NO_x reduction needs of utilities using cyclones and cell burners. The Ohio Coal Development Office (OCDO) also sponsored the cell burner project as part of its own Clean Coal Technology Program. Coal reburning to reduce NO_x emissions by at least 50% from cyclones was demonstrated at Wisconsin Power and Light Company's (WP&L) 110 MW_e Nelson Dewey Generating Station. The Low- NO_x CellTM burner (LNCBTM) reducing NO_x emissions by at least 50% was demonstrated at the 605 MW_e Unit No. 4 at Dayton Power & Light Company's (DP&L) J. M. Stuart Station. Both emissions and overall boiler performance test results for each Clean Coal Technology Demonstration are presented in this paper as well as present status of the technologies.

INTRODUCTION AND BACKGROUND

Coal Reburning

The "Coal Reburning for Cyclone Boiler NO_x Control Demonstration" (Project DE-FC22-90PC89659) is one of the U. S. Department of Energy (DOE) Clean Coal Technology, Round II (CCT-II) Demonstration Program Projects. The objective of the coal reburning demonstration is to evaluate the applicability of the technology to full-scale cyclone-fired boilers for reduction of NO_x emissions. The project goals are:

1. Achieve a minimum 50% reduction in NO_x emissions at full load.
2. Reduce NO_x without serious impact to cyclone operation, boiler performance or other emissions streams.
3. Demonstrate a technically and economically feasible retrofit technology.

The project participants providing funding for the work are:

- DOE - funding co-sponsor
- WP&L - host site utility and funding co-sponsors
- B&W - prime contractor, project manager and funding co-sponsor
- EPRI - testing consultant and funding co-sponsor
- State of Illinois Department of Natural Resource - funding co-sponsor
- Utility funding co-sponsors
 - Allegheny Power System
 - Atlantic Electric
 - Associated Electric
 - Baltimore Gas & Electric
 - Basin Electric Power Cooperative
 - Iowa Electric Light & Power Company
 - Iowa Public Service
 - Minnkota Power Cooperative, Inc.
 - Missouri Public Service
 - Montana-Dakota Utilities
 - Kansas City Board of Public Utilities
 - Kansas City Power & Light
 - Northern Indiana Public Service Company
 - Tampa Electric Company

Currently, 105 operating, cyclone-equipped utility boilers exist, representing approximately 13% of pre-NSPS coal-fired generating capacity (over 26,000 MW_e). However, these units contribute approximately 21% of the NO_x emitted because their inherent,

turbulent, high-temperature combustion process is conducive to NO_x formation. Typically, NO_x levels associated with cyclone-fired boilers range from 1.0 to 1.8 lb/10⁶ Btu input (NO_x as NO₂). Although the majority of the cyclone units are 20 to 30 years old, utilities plan to operate many of them for at least an additional 10 to 20 years. These units (located primarily in the Midwest) have been targeted for the second phase of the Clean Air Act Amendments of 1990 (CAAA) Title IV (Acid Rain Control) scheduled to go into effect in 2000. In some instances, Title I, Ozone Non-Attainment will accelerate the timetable for compliance.

No economical, commercially-demonstrated, combustion modifications have significantly reduced NO_x emissions without adversely affecting cyclone operation. Past tests with combustion air staging achieved 15 to 30% reductions. Further investigation of staging for cyclone NO_x control was halted due to corrosion concerns, as a result of reducing conditions in the cyclone during air staging. Additionally, because no mandatory federal or state NO_x emission regulation was enforced, no alternative technologies were pursued.

The use of selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR) technologies also offer the possibility of controlling NO_x emissions from these units, but at high capital and/or operating costs. Reburning is therefore a promising alternative NO_x reduction approach for cyclone-equipped units with more reasonable capital and operating costs. Reburning also complements a fuel switching SO₂ reduction strategy in that typical derates incurred in switching to a Western low sulfur subbituminous coal are offset by the reburn system's additional capacity.

The coal reburning full scale demonstration is justified via a previous EPRI-sponsored (Project RP-1402-30) engineering feasibility study and EPRI/GRI (EPRI RP-2154-11; GRI:5087-254-1471) pilot-scale evaluation of reburning for cyclone boilers performed by B&W^[1,2]. These works indicated that NO_x reduction potential was significant and that the technology would apply to the majority of the cyclone boiler population.

The reburning project spanned a 50 month period, September 1989 through October 1993.

Low NO_x CellTM Burner

The "Full-Scale Demonstration of Low-NO_x Cell Burner Retrofit" (Project DE-FC22-POP90545) is one of the U. S. Department of Energy (DOE) Clean Coal Technology (CCT-III) Demonstration Program projects and also part of OCDO CCT program. The objective of the LNCBTM demonstration is to evaluate the

applicability of this technology for reducing NO_x emissions in full scale, cell burner-equipped boilers. The program goals are:

1. Achieve at least a 50% reduction in NO_x emissions.
2. Reduce NO_x with no degradation to boiler performance or life.
3. Demonstrate a technically and economically feasible retrofit technology.

The project participants providing funding for the work are:

- DOE - funding co-sponsor
- DP&L - host site utility, operations and construction management and funding co-sponsor
- B&W - prime contractor, project manager and funding co-sponsor
- EPRI - testing consultant and funding co-sponsor
- OCDO - funding co-sponsor
- Utility funding co-sponsors
 - Allegheny Power System
 - Centerior Energy
 - Duke Power Company
 - New England Power Company
 - Tennessee Valley Authority
 - Cincinnati Gas & Electric Company
 - Columbus and Southern Power Company

Economic considerations, which dominated boiler design during the 1960s, led to the development of the standard cell burner for highly efficient boiler designs. Utility boilers equipped with cell burners currently comprise 13%, or approximately 26,000 MW_e of pre-NSPS coal-fired generating capacity. Cell burners are designed for rapid mixing of the fuel and oxidant. The tight burner spacing and rapid mixing minimize the flame size while maximizing the heat release rate and unit efficiency. Consequently, the combustion efficiency is good, but the rapid heat release produces relatively large quantities of NO_x. Typically NO_x levels associated with cell burners will range from 1.0 to 1.8 lb/10⁶ Btu input (NO_x as NO₂).

To reduce NO_x emissions, the LNCBTM has been designed to stage the mixing of the fuel and combustion air. A key design criterion for the burner was accomplishing delayed fuel-air mixing with no pressure part modifications, i.e. a plug-in design. The plug-in design reduces material costs and outage time required to complete the retrofit, compared to installing conventional, internally staged low NO_x burners, thus providing a lower cost alternative to address cell burner NO_x reduction requirements.

Justification for the LNCB™ full scale demonstration was based on a laboratory test program which was designed to fully characterize the LNCB™ at several scales: 1.7S MW_e, 30 MW_e, and utility scale^[3]. This development work was done in association with EPRI. Several aspects of the LNCB™ performance including NO_x reduction, unburned carbon (UBC), carbon monoxide (CO), corrosion and impact to furnace exit gas temperature (FEGT) were investigated. Results of the pilot scale studies showed that the LNCB™ burner arrangement was stable over the burner operating range and that greater than 50% NO_x reduction was possible with acceptable impact to CO, UBC, and FEGT levels^[4].

In 1985, one two-nozzle cell burner was replaced with an LNCB™ at DP&L's Stuart Station Unit No. 3 to test the mechanical reliability. After three years of normal burner operation, with no signs of material degradation, the test was deemed successful.

The LNCB™ project commenced in April 1990 with long term emission testing completed in April of 1993. The completion of corrosion testing scheduled for December 1994 will mark the end of the project.

COAL REBURNING

Description of Technology

The Coal Reburning technology combines pulverized coal combustion with existing cyclone-fired technology. Instead of all of the combustion taking place within the cyclones, 20 to 35% of the fuel is diverted to a pulverized coal system and fed to the reburn burners downstream of the cyclones. These additional burners are used to create a reducing zone within the main furnace area. Within this zone, stoichiometries of less than 1.0 are maintained for as long as possible to allow mixing and chemical reduction of NO_x to occur. Overfire air is added higher in the furnace to provide enough air to complete the combustion process. At the furnace exit, the stoichiometry matches the original, unmodified condition.

In the reburn zone, up to 35% (at lower loads) of the total heat input required by the boiler is introduced substoichiometrically. This creates large quantities of unburned (unoxidized) hydrocarbon gases which actively seek oxygen to complete the combustion process. Chemically, this oxygen comes from the NO_x molecules created in the cyclones. The reaction reduces the NO_x to elemental nitrogen (N₂). The combustion process is completed as the flue gas enters the overfire air zone where excess oxygen is available, but at a significantly lower temperature than found within the cyclone (2500 versus 3300F). This lower temperature limits NO_x reformation. Figure 1 presents the various combustion zones of the furnace: the main combustion zone, the reburn zone and the burnout zone.

Reburn System at Nelson Dewey Unit No. 2

The demonstration boiler host site at WP&L's Nelson Dewey Unit No. 2 is shown in Figure 2. The unit is a Babcock & Wilcox manufactured 100 MW_e cyclone fired RB boiler capable of firing bituminous and subbituminous coals. It is fired by three 9 ft. diameter cyclones equipped with vortex burners. Initial operation was in October of 1962.

The reburning system design activities included pilot-scale testing, physical and three-dimensional numerical modeling and engineering which incorporated B&W low NO_x burner/overfire air port design experience. With the objective of maximizing mixing in the reburn and overfire air zones, the size, number, and location of reburn burners and overfire air ports were determined. Application of Small Boiler Simulator (SBS)-Pilot Scale testing results as well as physical flow and numerical models to design of the reburn system are described elsewhere^[5,6].

The isometric view of the system shown in Figure 3 gives the spacial relationships of the four reburn burners and four overfire air ports, the MPS-67 pulverizer and hot primary air fan as well as the coal pipes, secondary air ducts, and gas recirculation flues.

Coal Reburning Test Results

The primary test coal for the coal reburning demonstration was an Illinois Basin bituminous coal (Lamar). The majority of the testing was performed while firing this fuel to reflect the higher sulfur bituminous coal fired by many of the utilities operating cyclones. Following the bituminous coal testing, subbituminous Powder River Basin (PRB) coal tests were performed to evaluate the effect of coal switching on reburn operation. In addition, WP&L's strategy to meet sulfur emission limitations as of January 1, 1993 is to fire the low sulfur coal. Reburning test parameters are described elsewhere^[6].

NO_x and CO Emissions

Baseline (no reburning) data for NO_x emissions under various load conditions for both coals are summarized in Figure 4 and in Table 1.

TABLE 1 - Baseline NO _x Levels for Lamar and PRB Coals		
Load (MW _e)	Baseline NO _x Emissions - ppm (lb/10 ⁶ Btu) Corrected to 3% Oxygen	
	Lamar Coal	Powder River Basin Coal
118	635 (0.86)	-
110	609 (0.83)	560 (0.75)
82	531 (0.72)	480 (0.64)
60	506 (0.69)	464 (0.62)
38	600 (0.82)	-

NO_x levels increase at 38 MW_e during Lamar firing because the boiler goes to single cyclone operation, approaching the heat release conditions and corresponding NO_x emissions achieved at full load.

CO emission levels during baseline operation were low while firing either of the two coal types. Generally speaking, the CO levels were slightly lower during the PRB coal firing tests (approximately 30 to 45 ppm versus 60 to 70 ppm over the load range).

Reburn testing on both the Lamar and PRB coals indicates that varying reburn zone stoichiometry is the most critical factor in changing NO_x emission levels during coal reburning operation. The reburn zone stoichiometry can be varied by altering the air flow quantities (oxygen availability) to the reburn burners, the percent reburn heat input, the gas recirculation flow rate or the cyclone stoichiometry.

Figure 5 represents B&W economizer outlet NO_x and CO emission levels in ppm corrected to 3% O₂ versus reburn zone stoichiometry at full load conditions (110 MW_e) while firing Lamar coal. This figure consists of parametric optimization and performance testing data. Figure 6 presents NO_x and CO emissions while firing PRB coal.

Load versus NO_x emissions for both coals are shown in Figure 7 and summarized in Table 2.

TABLE 2 - Reburn NO _x Emissions Versus Load for Lamar and PRB Coals		
Load (MW _e)	Reburn NO _x Emissions/% Reduction from Baseline (ppm/%)	
	Lamar Coal	PRB Coal
118	-	275/-
110	290/52	208/62
82	285/47	215/55
60	325/36	220/53
41	-	220/-

Reburn operation burning PRB produced lower overall NO_x emission levels. Baseline NO_x levels with PRB were approximately 10% lower, and better NO_x reduction is probably due to the higher Western fuel volatile content. Higher volatile content generates higher concentrations of hydrocarbon radicals in the substoichiometric region of the furnace. Figure 7 also shows that PRB NO_x emissions could be maintained at a constant level - over the 110 to 41 MW_e load range.

With PRB coal, at loads higher than 110 MW_e NO_x emissions increased. At 118 MW_e, the NO_x level was 275 ppm (0.37 lb/10⁶ Btu). Higher NO_x was due to less percent reburn heat input because of reburn feeder limitations. No baseline NO_x level were obtained at this higher load because the boiler could not reach it on PRB coal without reburn burners in service.

Other Operating Parameters

Impact of the reburn process with both Lamar and PRB coals on electrostatic precipitation performance, unburned carbon efficiency loss, furnace exit gas temperature, slagging and fouling, furnace corrosion and hazardous air pollutant emissions are described in detail elsewhere^[6].

Table 3 presents a summary comparison of anticipated and actual results of reburn operation for these parameters.

TABLE 3 Effect of Reburn System on Unit Performance		
Parameter	Anticipated Results	Actual Results
NO _x Emissions (full load) Illinois Basin Coal	Reduced 50% or more	Nominal 55% reduction
NO _x Emissions (full load) Powder River Basin Coal	Reduced 50% or more	Nominal 61% reduction
Precipitator capacity	Up 5 to 10%	No increase from base
Slagging/Fouling	No change	Cleaner than normal
Furnace corrosion	No change	No change
Header/tube temps.	Higher 25 to 50F	No increase from base
FEGT (Illinois Basin - Lamar coal)	Higher by 50 to 75F	Reduced by 100 to 150F
FEGT (PRB)	Higher by 50 to 75F	Reduced by 25 to 50F
SH & RH sprays (Illinois Basin - Lamar coal)	Higher by 30%	50% of base
Unburned carbon efficiency loss (Full load) Illinois Basin Coal	Higher	Higher by 0.1%
Unburned carbon efficiency loss (Full load) Powder River Basin Coal	Higher	No change
Hazardous air pollutants (Illinois Basin - Lamar coal)	No change	No change

Fuel Switching Advantage

A significant advantage of coal reburning is that it minimizes and possibly eliminates a 10 to 25% derate normally associated with switching to a PRB coal in a cyclone unit. The derate is a result of using of lower Btu content fuel in the volume limited cyclone. The reburn system transfers about 30% of the heat input out of the cyclones to the reburn burners, bringing the cyclone feed rate down to a manageable level, while maintaining full load heat input to the unit. At Nelson Dewey, maximum pre-reburn

retrofit full load on PRB coal was 108 to 110 MW_e, while on the higher Btu Lamar coal, 118 MW_e could be achieved. With reburn in operation, the unit was able to achieve 118 MW_e on PRB coal. Accordingly, there is a possibility to economically justify a reburn system based on fuel cost savings and regained unit capacity when switching to a PRB coal. This is a site specific issue based on ability of the unit to fire PRB coal and deal with the other impacts such as slagging and fouling.

Reburn Technology Status

The reburn system has performed very well as evidenced by WP&L's decision to take title of the system and operate it beyond the term of the DOE project. Current operation is less frequent than anticipated, on the order of once a week for a period of a day. The reason for reduced operation is a problem with the hot primary air fan variable frequency AC drive which controls fan speed. The fan provides hot air to dry and convey the pulverized coal to the burners. Once the PA fan drive problem is resolved, WP&L will resume regular reburn system operation. Also, when burning 100% PRB coal, problems with convection pass fouling have occurred due to the nature of the fuel. From a commercialization point of view, a number of utilities have asked B&W to perform engineering studies on their respective units to determine expected performance and cost.

LOW NO_x CELL BURNERS (LNCBTM)

Description of Technology

The original cell burner design consisted of two or three circular burners mounted in the lower furnace. Figure 8 shows a two-nozzle cell burner. The two-nozzle LNCBTM shown in Figure 9 was developed by B&W in association with the EPRI. The features of the LNCBTM were designed to minimize the formation of thermal and fuel NO_x. The two original circular burners in each cell are replaced with a single S-type circular burner and a close coupled secondary air injection port. The flame shape is controlled using an impeller at the exit of the burner and adjustable spin vanes in the secondary air zone. The air port louver dampers provide additional control over the mixing between the fuel and air streams. The S-burner operates at a low air-fuel stoichiometry, typically 0.6, with the balance of air entering through the adjacent air port. The delayed mixing of the fuel and air during the initial stage of combustion limits the formation of NO_x.

Low NO_x Cell Burners at J.M. Stuart Station Unit No. 4

The host site for the full scale demonstration of the LNCBTM was DP&L's J.M. Stuart Station Unit No. 4 (JMSS4). JMSS4 is a B&W 605 MW_e Universal Pressure (UP) boiler, a once-through design, originally equipped with 24, two-nozzle cell burners arranged in an opposed wall configuration as shown in Figure 10.

Each of the original two-nozzle cell burners were replaced with a single S-type circular burner in place of the lower cell burner and a close coupled secondary air injection port at the upper cell location, shown in Figure 9. To avoid replacing coal pipes and pulverizer top housings, the two coal pipes, one to each burner of the original cell, were combined at the burner front to supply the new single S-type circular burner by using a special Y-pipe assembly. As a special feature of the LNCBTM technology, no pressure part modifications were necessary and the existing control system was utilized. The retrofit of the LNCBTM equipment was completed during a six week scheduled turbine outage during October/November 1991.

Initial test results with this original arrangement (Figure 11) indicated high levels of CO and hydrogen sulfide (H₂S) in the lower hopper region of the furnace, an unacceptable operating condition in this pressurized furnace. As a demonstration project, resources were allocated to perform in depth background work to develop the numerical model to help understand flow behavior in the unit. When problems with the LNCBTM operation arose, B&W used its three dimensional numerical modeling capabilities to simulate the existing operating condition, as well as evaluate alternative burner/secondary air port arrangements that could mitigate this problem. The best computer generated analysis identified for maximum mitigation of CO and H₂S levels was to invert the air port and burner of every other LNCBTM on the lowest level of burners (Figure 12)^[7]. This is the final configuration of the LNCBTM system tested during the project.

A second result of initial testing showed that NO_x reduction of only 35% from baseline levels was being achieved with the 50 degree coal impellers. By retracting the impellers within the coal nozzles, NO_x reduction increased to 45%. This indicated a need for an impeller design change in order to achieve the NO_x reduction goals of the project. A coal impeller with a 25 degree included angle was designed, fabricated and installed during the same one week outage in April 1992 in which the alternating inverted LNCBTM arrangement was accomplished.

Low NO_x Cell Burner (LNCBTM) Test Results

The LNCBTM demonstration emphasized evaluation of boiler performance, boiler life and environmental impact. Key boiler performance parameters that were measured included boiler output (steam temperatures); flue gas temperatures at the furnace, economizer and air heater exits; the slagging tendencies of the unit; and UBC losses. Evaluation of H₂S levels, ultrasonic testing of lower furnace tube wall thicknesses and destructive examination of a corrosion test panel were the mechanisms used to predict impact on remaining boiler life. Environmentally, NO_x, CO, carbon dioxide (CO₂), total hydrocarbons (THC) and particulate matter, dust loadings and precipitator collection efficiency were measured at varying test conditions.

Performance results during parametric testing for NO_x, CO emissions and unburned carbon losses are described in detail

elsewhere [6,8]. In general, full load (604 MW_e) NO_x emissions with all mills in service averaged .53 lb/10⁶ Btu, representing a 54.4% reduction. At full load with five mills in service, NO_x emissions ranged from 0.48 to 0.56 lb/10⁶ Btu depending on which mill was out of service. When mills fueling the upper burners were out of service, the best NO_x reductions were obtained. This is possibly due to deeper staging of lower burners, which are fired harder with one mill out of service, followed by higher secondary air availability at the burner out-of-service level. CO levels did not exceed 55 ppm and efficiency losses due to unburned carbon were significantly improved, with all mills in-service and only slightly improved for one mill out of service.

At intermediate load (460 MW_e) NO_x emissions were 0.42 lbs/10⁶ Btu, a 54% reduction. CO levels were in the 28 to 45 ppm range and unburned carbon efficiency improved significantly. At low load (350 MW_e) NO_x emissions were 0.37 lbs/10⁶ Btu, a 48% reduction. CO ranged from 5 to 27 ppm and efficiency loss due to unburned carbon increased slightly.

Long Term Averages

An important aspect of the project was to record NO_x emission levels from JMSS4 during normal load dispatch operations over a long period. Table 4 and Table 5 show the average NO_x emissions for JMSS4 with all mills in service and one mill out of service, respectively. This data was recorded by the Acurex CEM equipment through a total of two probes located one in each of the east and west economizer outlet ducts. This data was acquired between August 1992 and March 1993 during periods when the boiler was operating above 590 MW_e.

TABLE 4 - LONG TERM FULL LOAD ALL MILLS IN SERVICE DATA					
All Mills in Service Averages at JMSS4 Acurex CEM Test Results for Loads Above 590 MW _e					
Month	Days * @ Full Load All Mills	All Mills in Service			
		Load MW _e	Dry O ₂ Econ Out	Dry NO _x ppm Corr to 3% O ₂	NO _x lb/10 ⁶ Btu
August	8.54	604	3.7	367	0.50
September	7.29	604	3.2	333	0.45
October	14.51	605	3.3	367	0.50
November	12.03	605	3.2	345	0.47
December	4.94	605	3.1	360	0.49
January	6.83	605	3.2	410	0.56
February	7.22	606	3.2	364	0.50
March	17.66	602	2.9	353	0.48

TABLE 4 - LONG TERM FULL LOAD ALL MILLS IN SERVICE DATA					
All Mills in Service Averages at JMSS4 Acurex CEM Test Results for Loads Above 590 MW _e					
Month	Days * @ Full Load All Mills	All Mills in Service			
		Load MW _e	Dry O ₂ Econ Out	Dry NO _x ppm Corr to 3% O ₂	NO _x lb/10 ⁶ Btu
Weighted 8-mo Avg.		604	3.2	360	0.49
Total Days 79.02 * Remaining days at lower load or mill out of service.					

TABLE 5 - LONG TERM FULL LOAD MILL OUT OF SERVICE DATA					
Mill Out of Service Averages at JMSS4 Acurex CEM Test Results for Loads Above 590 MW _e					
Mill Out of Service	Days * @ Full Load 1 Mill Out	August '92 - March '93			
		Load MW _e	Dry O ₂ Econ Out	Dry NO _x ppm Corr to 3% O ₂	NO _x lb/10 ⁶ Btu
A	1.04	603	3.4	314	0.43
B	1.81	608	3.6	361	0.49
C	1.41	602	3.5	388	0.53
D	2.29	602	3.6	404	0.55
E	3.02	606	3.3	357	0.49
F	8.48	604	3.9	314	0.43
Weighted 8-mo Avg.		604	3.7	343	0.47
Total Days 18.05 * Remaining days at lower load or all mills in service.					

With all mills in service, the average NO_x level achieved for the eight month period was 0.49 lb/10⁶ Btu or a 58% reduction from baseline. The highest monthly average NO_x level observed was in January at 0.56 lb/10⁶ Btu. Wet coal and accompanying problems were suspected to have caused the higher level which still represented a 52% reduction. The excess O₂ levels averaged 3.2%.

For full load, mill out service NO_x emission levels (Table 5) averaged 0.47 lb/10⁶ Btu. The lower NO_x levels recorded with either A or F mill out of service, as observed previously, can be

attributed to the fact that these mills feed the burners on the upper elevation only.

Long-Term Operational Performance

The operational performance of the Low-NO_x Cell™ Burner (LNCB™) equipment has been good since the final arrangement and impeller modifications were made in April 1992. The LNCB™s have been providing stable combustion conditions with good carbon burnout.

The amount of flyash produced appears to have increased while the amount of bottom ash has decreased. The flyash appears to be finer as compared to that produced with the original cell burners. Even though the overall dust loading has increased, the performance of the precipitators has improved.

The cell burners formerly produced a buildup of agglomerated "popcorn" ash on the horizontal convection pass sections of the boiler, particularly on the economizer. This ash buildup and associated tube erosion has been greatly reduced since the installation of the LNCB™s. The required maintenance associated with the airheaters, the flyash handling equipment, and the bottom ash handling equipment has been reduced due to the condition of the ash produced by the LNCB™s in this boiler.

Corrosion Studies

During burner installation in October/November 1991, a corrosion test panel was installed on the boiler side wall between the upper and lower burner rows to evaluate corrosion potential. The panel consists of SA-213T2 bare tube material, aluminized spray coated T2 tube material and a chromized T2 tube material. In addition, UT measurements were conducted in the furnace.

Destructive examination of the furnace wall samples taken from the corrosion test panel was performed. In addition, predictive equations were developed based on laboratory investigations.

The long-term corrosion panel test in J.M. Stuart Station Unit #4 (JMSS 4) indicates that the maximum metal wastage of SA213-T2 is approximately 21 mils after the 15-month operating period.

This wastage rate is equivalent to a corrosion rate of 17 mpy. Based on predictive equations developed during the long-term test task, maximum metal wastage of T2 was calculated to be 15 mpy. These equations based their predictions upon: 1) the metal temperature, 2) H₂S concentration in the flue gas, and 3) Cr concentration in the alloys under the test conditions employed.

All of the commercial high-alloy steels investigated in this task, including a popular and economical steel -- SA213-TP304, appear to possess suitable corrosion resistance to the laboratory mixed gases. Their good performance was also confirmed by the field test. Therefore, the selective use of chromia-forming alloys in areas of the boiler where chemically reducing flue gases have wall contact should alleviate the corrosion concern of many low-NO_x technologies.

By contrast, the corrosion performance of carbon and low-alloy steels commonly used in the lower furnace of utility boilers may suffer due to sulfidation attack under reducing combustion gases. Therefore, these materials require surface protection locally in the lower furnace where reducing gases are present. However, high tube wastage was reported prior to the retrofit in JMSS4 where reducing combustion gases were suspected.

Results of the field test suggest that a chromia-forming coating relatively free of structural defects may be locally applied to the surfaces of waterwalls to combat the above noted sulfidation attack. However, these corrosion resistant materials can be significantly affected by their microstructure integrity. When pre-existing structural defects, such as cracks, pores, and oxide stringers are present, the corrosion attack can proceed preferentially along these sites. As a result, the metal wastage can be much greater than anticipated when the surface coatings are not applied properly.

UT testing of the furnace will continue over the next five years to evaluate corrosion potential.

Commercial Status of LNCB™ Technology

Since the completion of the test program, B&W has pursued commercialization of LNCB™ technology. To date, commercial sales have resulted for 5 units, totalling 3300 MW_e. These include three units at Allegheny Power System (APS) and two units at Detroit Edison. As of this time, Hatfield's Ferry Unit No. 2 of Allegheny Power has been installed and started up. All others are in stages of engineering and fabrication. These represent the first commercial sales of a DOE Clean Coal Technology developed in the Clean Coal Program.

The LNCB™ system at Hatfield's Ferry Unit No. 2 was installed during an eight week outage, September 24 through November 23, 1993, concurrently with major turbine work. This system included an upgraded design of the commercial B&W NO_x port (overfire air port) which reduced resistance to air flow. This was made possible through a downsizing of the air distribution bluff body within the port. The stoichiometries used at Stuart Station can be achieved at Hatfield's Ferry with a windbox to furnace differential pressure in the range of 1.7 in WC lower (Stuart 4.5 in WC and Hatfield's Ferry 2.8 in WC).

Preliminary results at Hatfield's Ferry reveal NO_x reductions at the 50% level have been achieved with no significant impact on unburned carbon efficiency loss.

For cell burner units in general, application specific burner zone heat release rates, furnace configuration, and coal type (ex. volatility, fixed carbon level, bituminous versus subbituminous, nitrogen content, and oxygen content etc.) will impact expected NO_x results. Boilers firing fuels similar to DP&L's J.M. Stuart Station are expected to experience at least a 50 percent NO_x reduction when retrofitted with LNCB™ technology.

Units with higher burner zone heat release rates than J.M.Stuart Station will generally have higher baseline NO_x levels. For these units, LNCBTM technology has the potential to reduce NO_x emissions by 50 percent from baseline levels, but not necessarily to absolute levels as low as those attained at DP&L Stuart Station.

The pre-retrofit burner equipment at DP&L had not been upgraded from its original configuration. The air registers on most of the pre-retrofit burners had been welded in an open position, and no work had been performed recently to balance air and fuel flows. Therefore some combustion relation items such as furnace exit gas temperature (FEGT), surface cleanliness, and unburned carbon results were improved by the mechanical improvements and air balancing capability of the LNCBTM equipment.

If a unit is similar to Stuart Station where there has been no major burner equipment or combustion upgrades, then similar results can be expected. However, if mechanical improvements have already been made to the burners such that "per burner air control" and/or per burner fuel/air balancing has been improved, then:

- a. FEGT may be slightly higher than baseline. Numerical modeling results indicated that in a balanced configuration, a 10°F increase in FEGT may result.
- b. Surface cleanliness will not show as dramatic an improvement because combustion efficiency will have already been improved.
- c. Unburned carbon losses may be slightly higher. The impact was minimized during the DOE demonstration program because the Stuart Station unit fuel/air flow was not balanced.

All other performance related parameters should have the same pre- to post-retrofit results as DP&L Stuart Station demonstration.

As far as corrosion potential is concerned, laboratory results suggest that there is a significant potential for localized furnace tube wall corrosion to occur. However, this risk is no greater than the risk associated with any other two-stage combustion process (i.e. overfire air system). There is evidence to suggest that the risk is no greater than the potential for corrosion with the current cell burner equipment. It is strongly suggested that steps be taken at the time of installation of this or any other staged combustion process, to also add commercially available products such as wall coatings that retard furnace wall corrosion.

CONCLUSIONS

Both the Coal Reburning and LNCBTM projects have achieved the respective Clean Coal Program objectives. Both technologies have

demonstrated NO_x reductions in excess of 50% without significant adverse impact to other boiler emissions streams. The host site units have each continued to reach pre-retrofit full load output without significant impact to boiler operation. Results of long term emissions testing indicate performance has continued to exceed the project goals for each technology and both DP&L and WP&L^[8] have decided to operate the respective Clean Coal Technologies beyond the project end dates.

The low cost and short outage time for a LNCBTM retrofit make the design financially attractive. In a typical retrofit installation, the capital cost will include the LNCBTM hardware, coal pipe modifications, hangers, support steel, sliding air damper drives and associated electrical, with a capital cost of about \$5.5 to \$8.0 per kW in 1993 dollars, based upon the DOE 500 MW_e reference unit for material and erection. The outage time can be as short as five weeks because the LNCBTM is a plug-in design.

For cyclones, coal reburning offers a NO_x reduction alternative at a higher price. Costs are expected to be in the \$65/kW range for a 100 MW_e unit and in the \$40/kW range for a larger 600 MW_e unit. Unlike a burner retrofit which already has coal handling and pulverizers/coal piping in place, this equipment must be included in the cost of a reburn system. Site specific factors related to pulverizer location and coal supply can greatly influence overall reburn system cost. However, coal reburning brings with it benefits allowing increased flexibility in coal selection which can yield significant fuel savings.

Corrosion potential will continue to be investigated over the next five years for both technologies.

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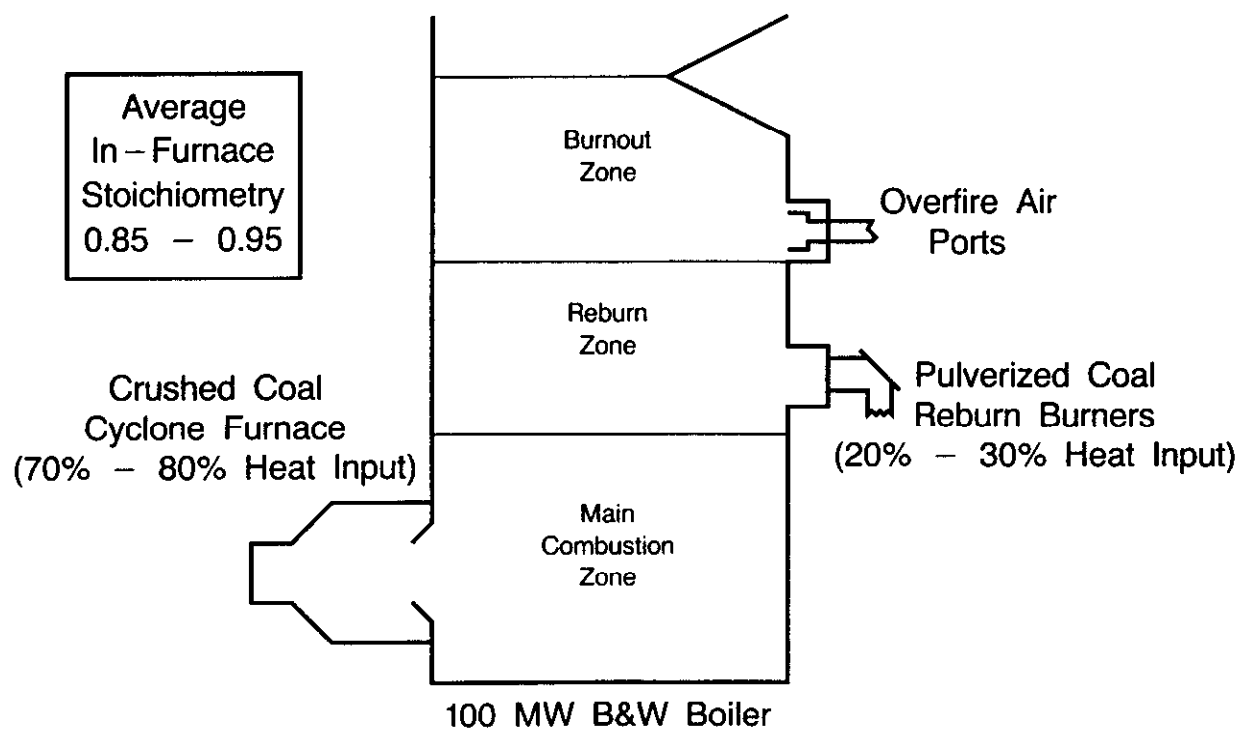


Fig. 1 Cyclone reburn combustion zones.

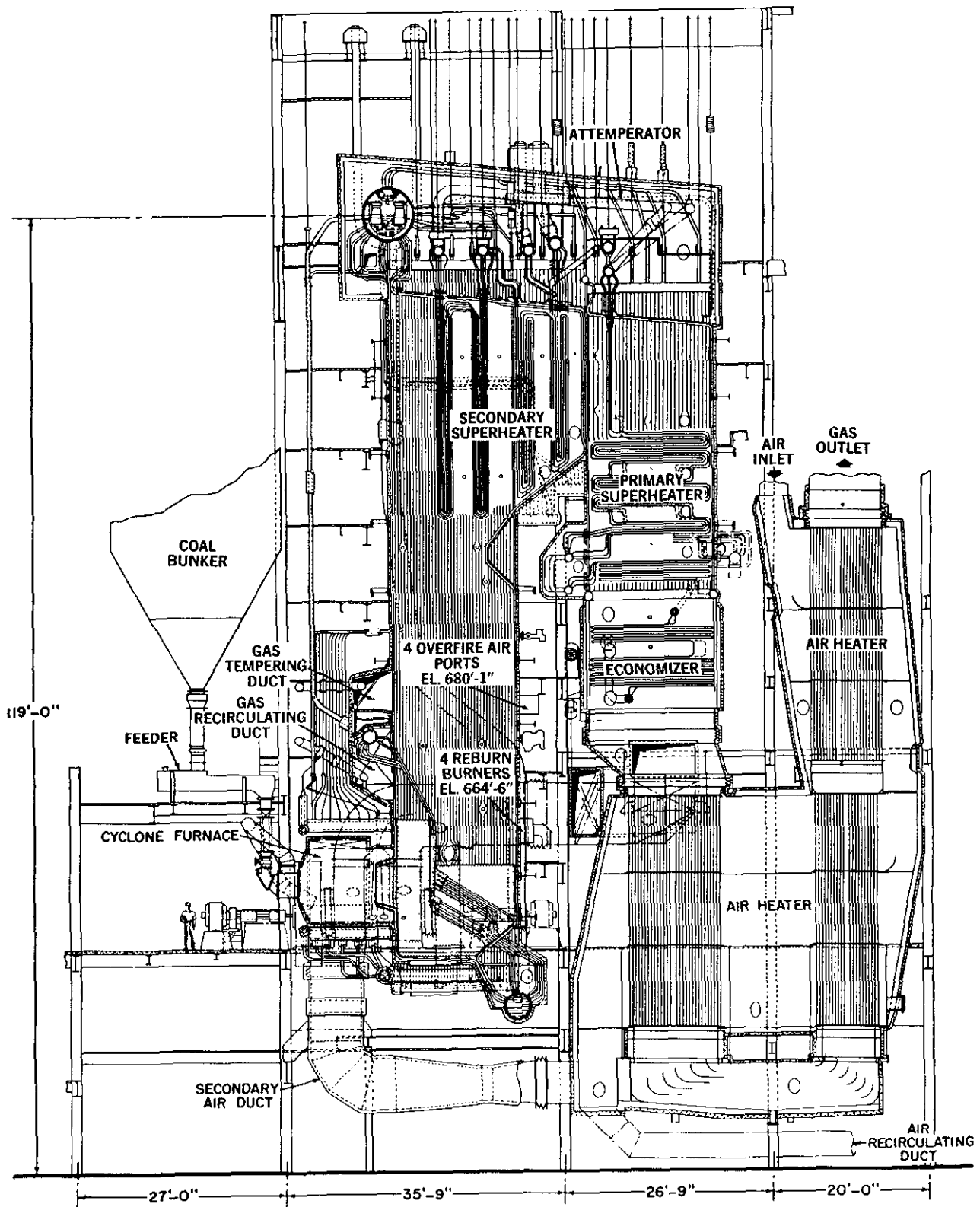


Fig. 2 WP&L Nelson Dewey Unit No. 2.

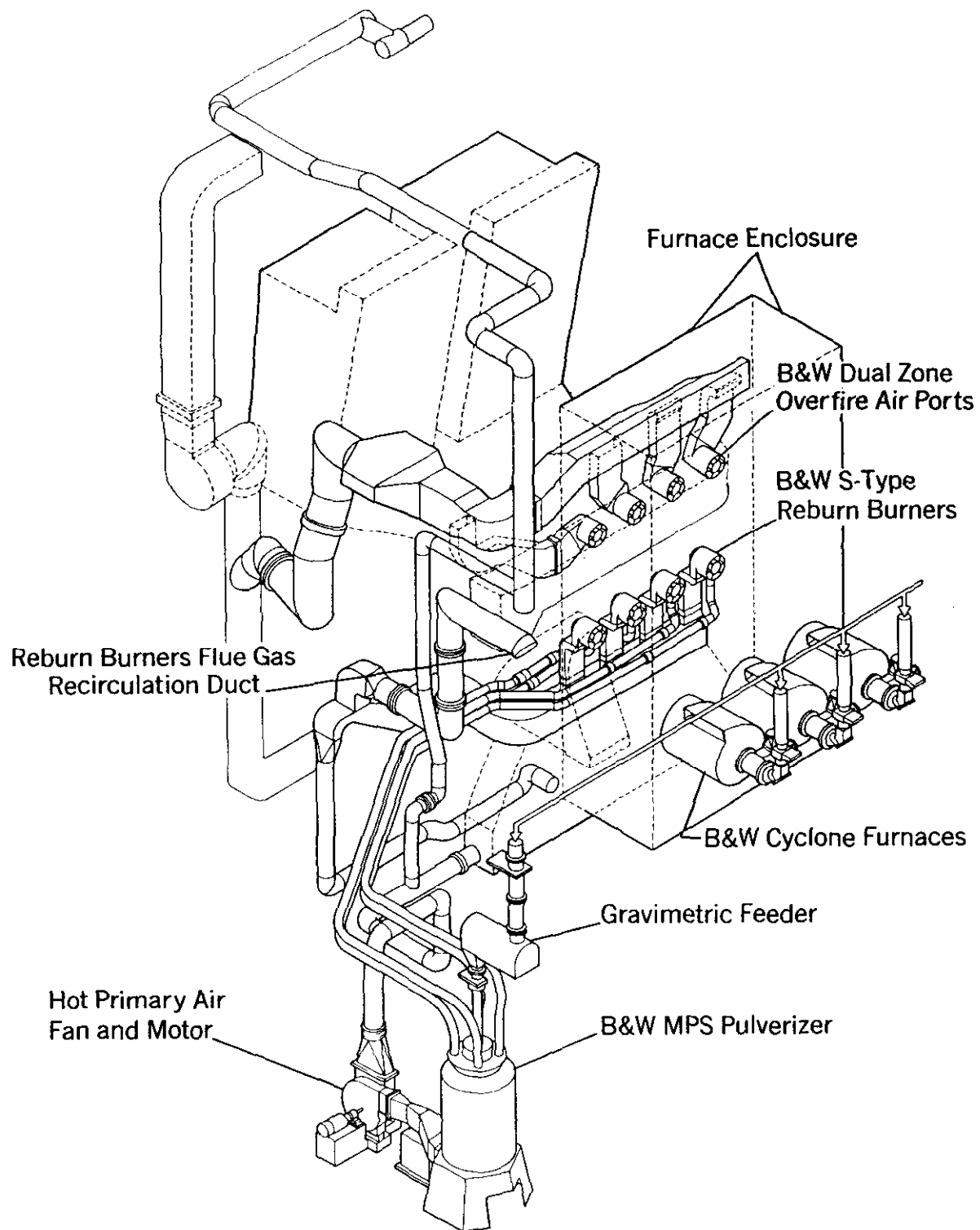


Fig. 3 Isometric view of Coal Reburning for Cyclone Boiler NO_x Control.

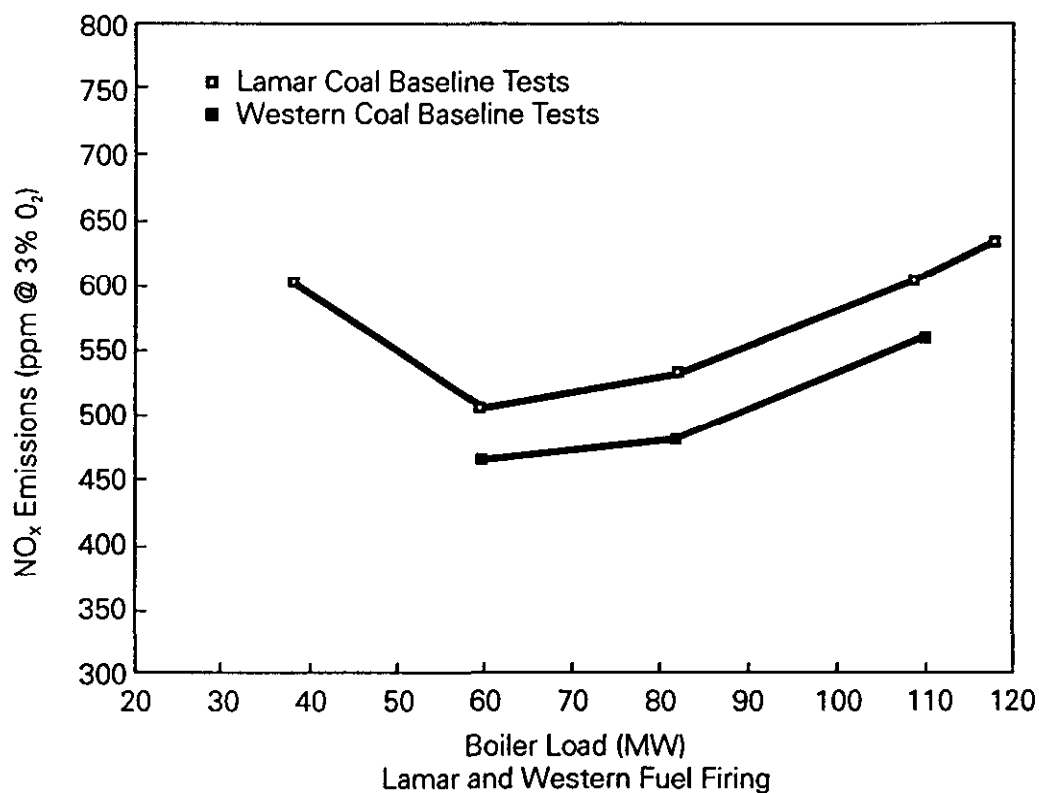


Fig. 4 Baseline NO_x emissions versus load, Nelson Dewey Unit 2.

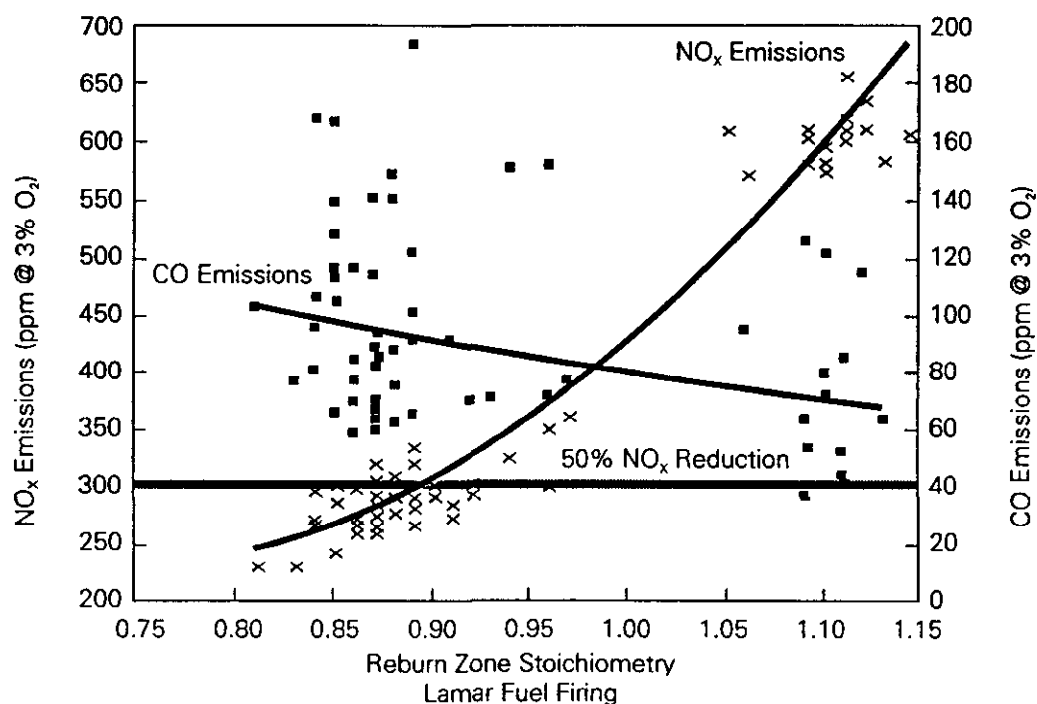


Fig. 5 NO_x and CO emissions versus reburn zone stoichiometry at full load firing Lamar coal.

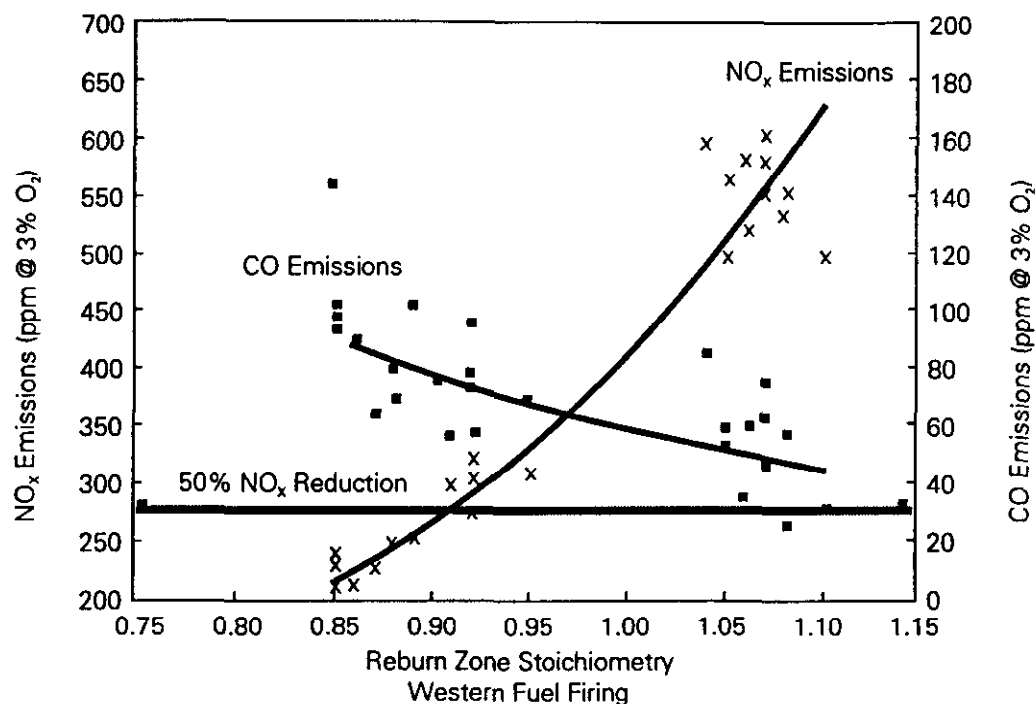


Fig. 6 NO_x and CO emissions versus reburn zone stoichiometry at full load firing Western coal.

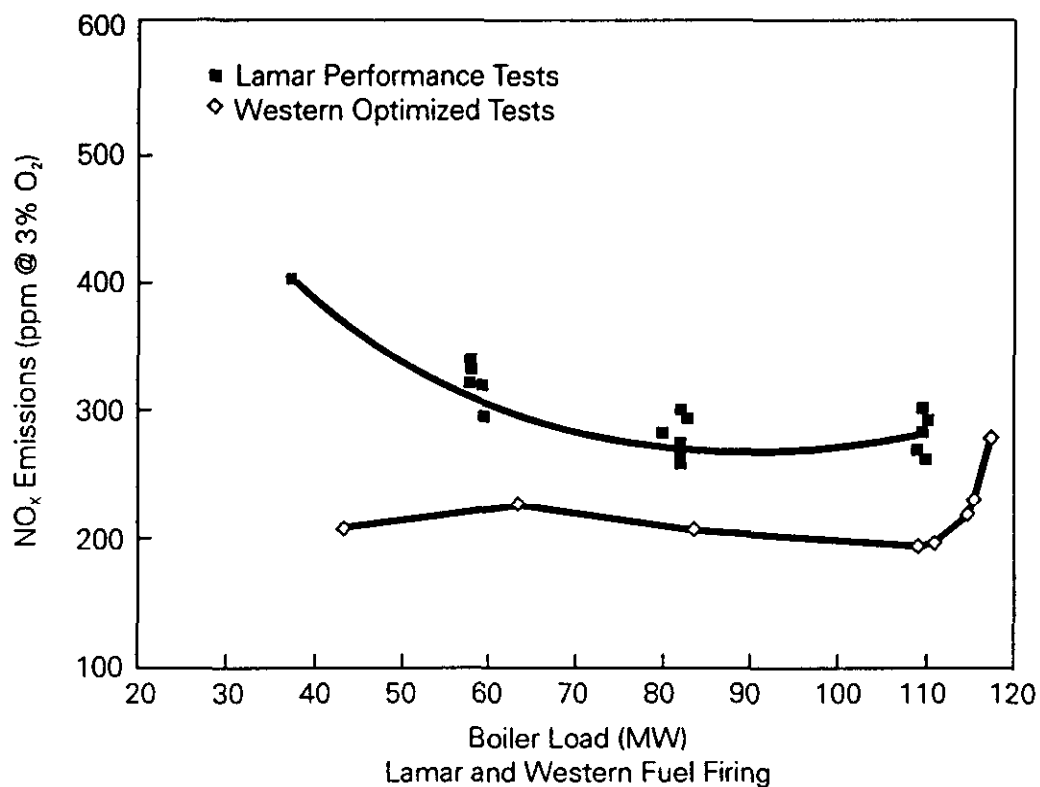


Fig. 7 NO_x emissions versus load firing Lamar and Western coals with reburn system in operation.

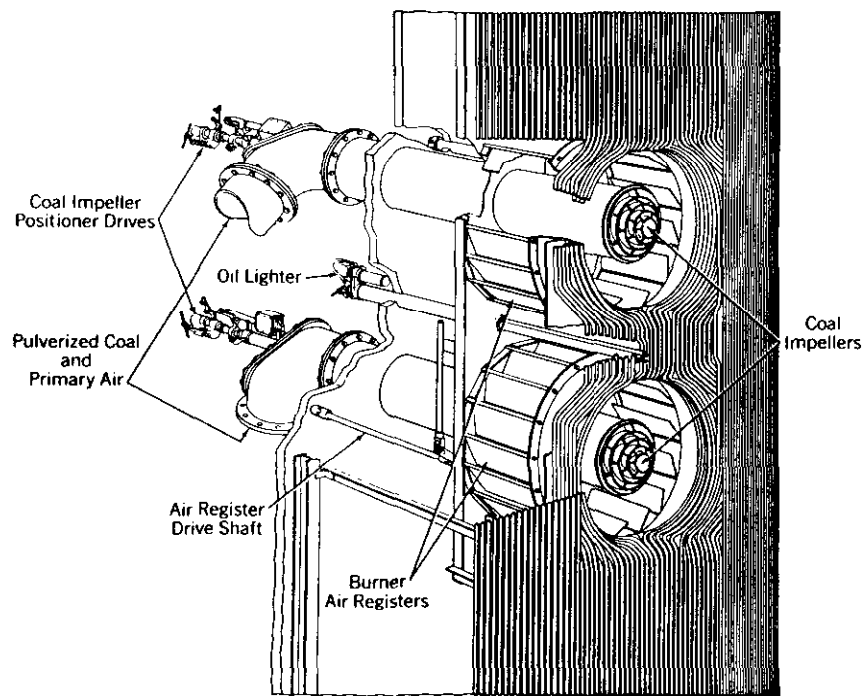


Fig. 8 Standard two-nozzle cell burner.

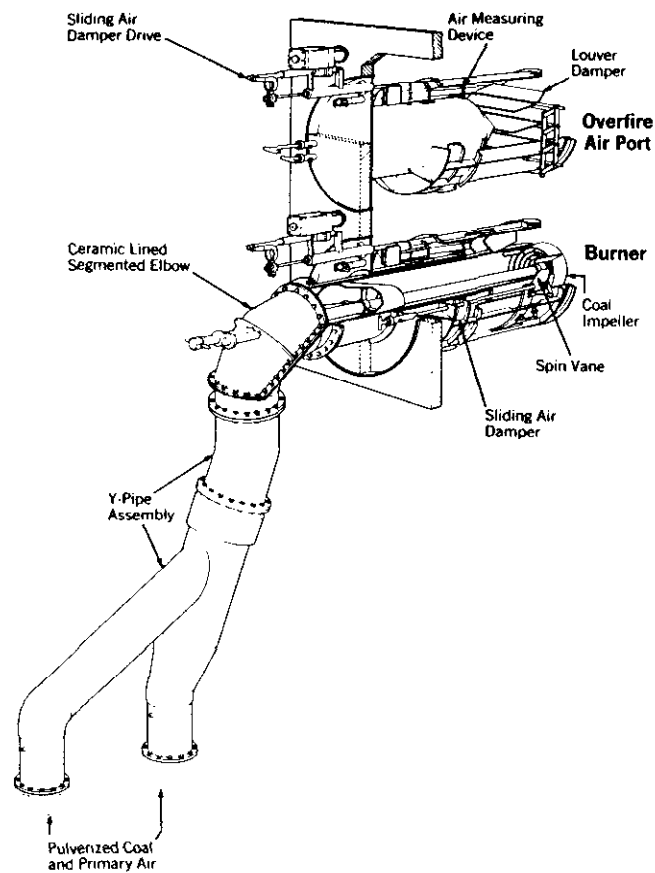


Fig. 9 Low NO_x Cell™ burner.

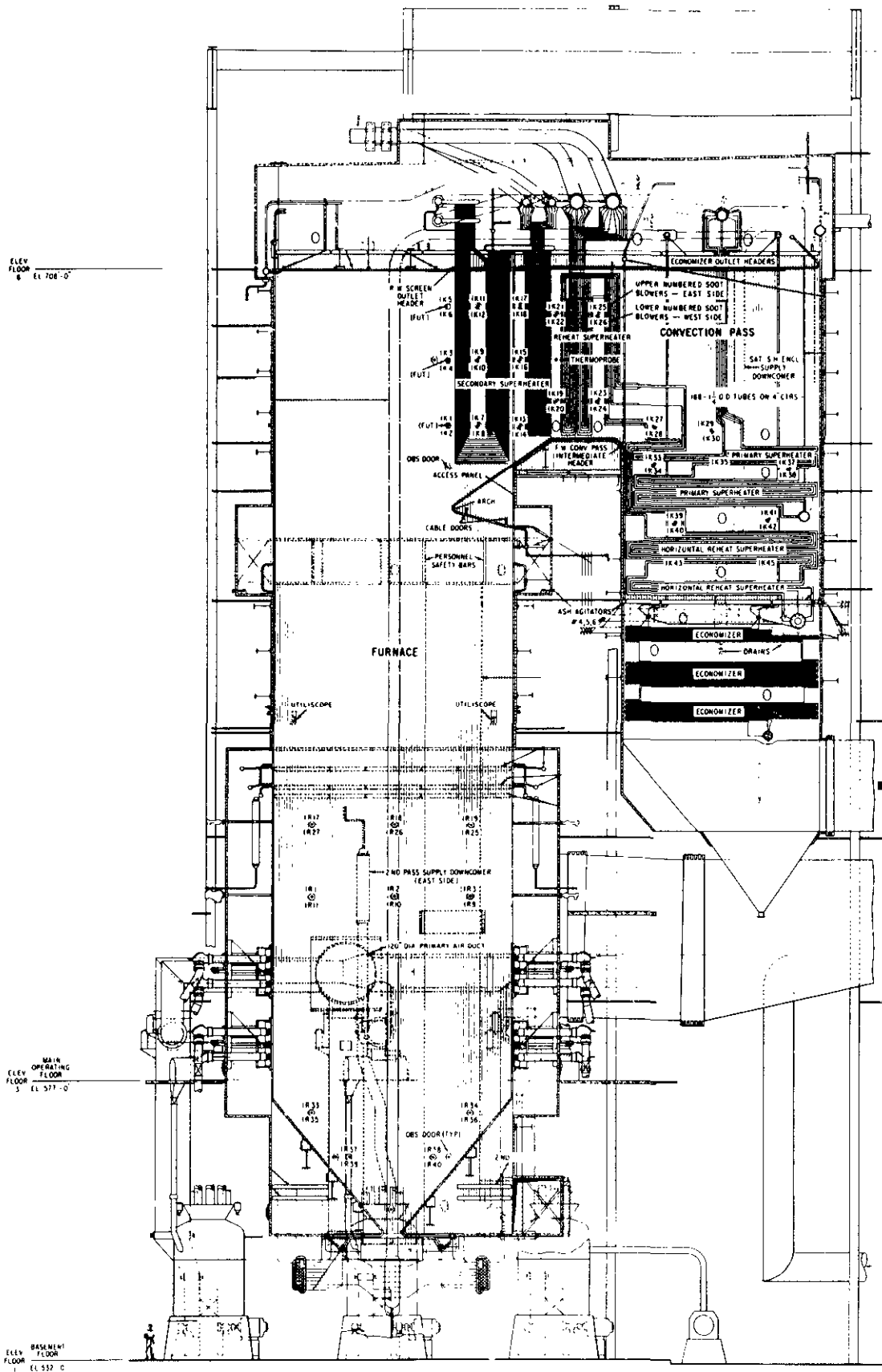


Fig. 10 DP&L J.M. Stuart Station Unit No. 4.

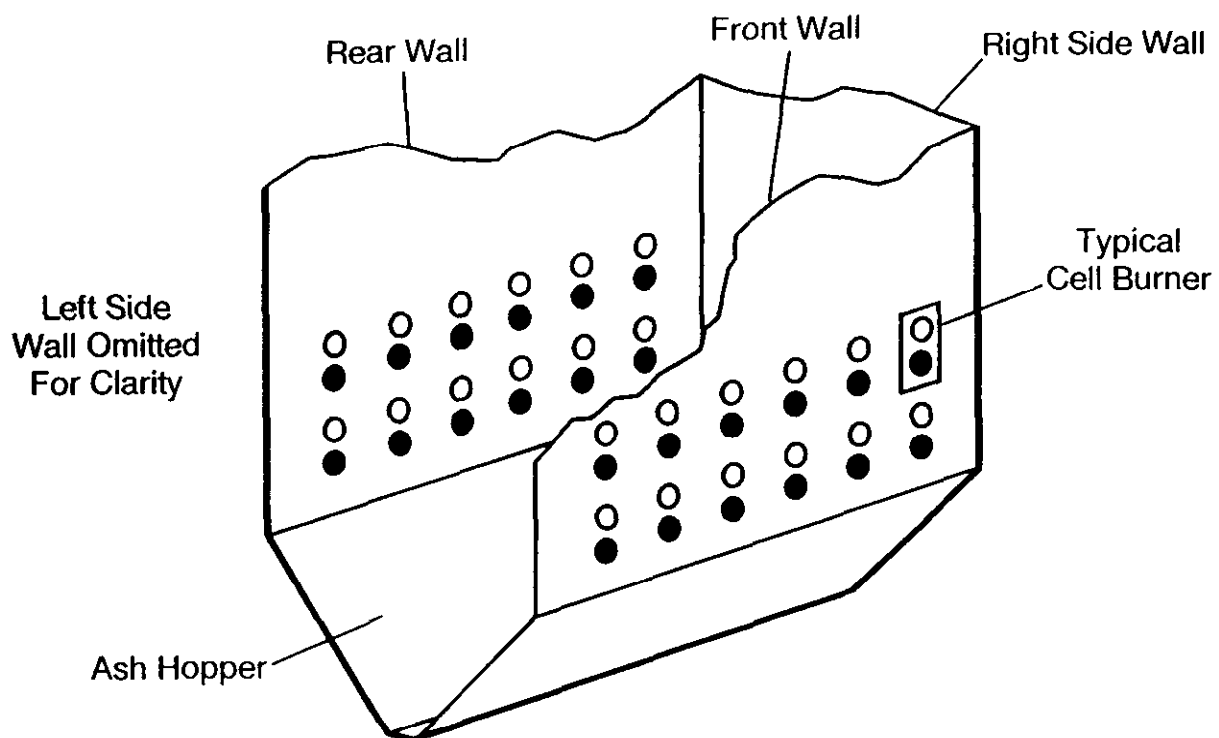


Fig. 11 Original LNCB™ arrangement.

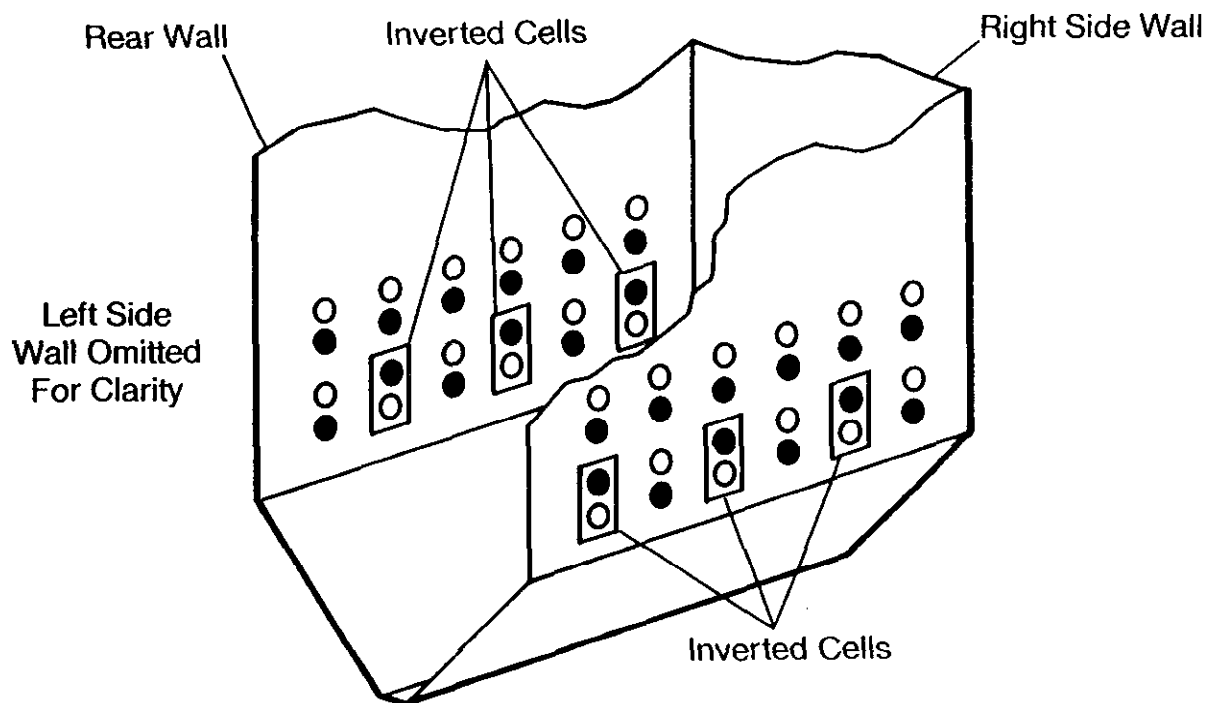


Fig. 12 Partially inverted LNCB™ arrangement.

**GAS REBURNING IN TANGENTIALLY,
WALL-, AND CYCLONE-FIRED BOILERS**

AN INTRODUCTION TO SECOND-GENERATION GAS REBURNING

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**Third Annual Clean Coal Technology Conference
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Chicago, Illinois**

ABSTRACT

The Energy and Environmental Research Corporation (EER) has achieved a total of 4,642 hours of successful Gas Reburning demonstration on three coal-fired utility boilers as of April 30, 1994. Typically, NO_x reduction has been above 60% in long-term, load-following operation. Gas Reburning has only minor impacts on boiler thermal performance.

At Illinois Power's Hennepin Station, Gas Reburning in a 71 MWe tangentially fired unit achieved an average NO_x reduction of 67%, from the original baseline NO_x of 0.75 lb NO_x/10⁶ Btu (323 g/GJ), in a one year demonstration test. The nominal gas input was 18% of the total heat input. Reburning with 10% gas heat input resulted in NO_x reduction of 55%. After completion of the project, Illinois Power retained the Gas Reburning system for potential NO_x compliance.

At Public Service Company of Colorado's Cherokee Station, a Gas Reburning system and low NO_x burners were retrofitted to a 172 MWe wall-fired unit (Unit 3). The combined technologies achieved NO_x reductions of 60-73% in parametric and long-term testing, from the original baseline NO_x level of 0.73 lb/10⁶ Btu (314 g/GJ). NO_x reductions of 60-65% were measured even with 5-10% gas heat input (18% original design). NO_x reduction by low NO_x burners alone was typically 30-40%. NO_x emissions were insensitive to a change in recirculated flue gas flow, employed to inject the natural gas. The system has been modified for operation with low gas input, without flue gas recirculation, and has improved overfire air ports. This second-generation Gas Reburning system will undergo testing for approximately 5 months.

At City Water, Light and Power Company of Springfield, Illinois, Gas Reburning in a 33 MWe cyclone-fired unit has achieved NO_x reduction averaging 66% (range 52-77%), at gas inputs of 20-26%, from a baseline NO_x level of 1.0 lb/10⁶ Btu (430 g/GJ).

This paper summarizes the NO_x control performance and other impacts of long-term Gas Reburning operation on tangential-, cyclone-, and wall-fired units.

INTRODUCTION

The Energy and Environmental Research Corporation (EER) is conducting field evaluations in two U.S. Department of Energy co-funded Clean Coal Technology (CCT) projects⁽¹⁻⁴⁾ involving two integrated technologies (Gas Reburning with Sorbent Injection and Gas Reburning with Low NO_x Burners (LNB)) on three coal-fired utility boilers with tangential-, cyclone-, and wall-firing modes (Table 1). Gas Reburning, in conjunction with Sorbent Injection, has been demonstrated on the tangential- and cyclone-fired units, while Gas Reburning and LNB have been applied to the wall-fired boiler.

- Tangentially fired boiler, Hennepin Station Unit 1, a 71 MWe unit, owned and operated by Illinois Power Company at Hennepin, Illinois. Long-term demonstration testing was completed in October, 1992. Illinois Power has retained the Gas Reburning system for potential NO_x compliance.
- Cyclone-fired boiler at Lakeside Unit 7, a 33 MWe unit, owned and operated by City Water, Light & Power Company, the municipal utility of the city of Springfield, Illinois. Long-term demonstration testing was completed in June, 1994. The host utility has decided to retain the Gas Reburning system.
- Wall-fired boiler at Cherokee Station, Unit 3, a 172 MWe unit, owned and operated by Public Service Company of Colorado in Denver, Colorado. Long-term demonstration testing started in April 1993. Modifications to the Gas Reburning system have been completed. The second-generation system will undergo extensive testing during the second half of 1994.

The goals for NO_x reduction are 60-70% and for SO₂ reduction, under Gas Reburning with Sorbent Injection, is 50%. The total cost of the two demonstration projects at three sites is \$55.4 million.

GAS REBURNING PROCESS

Gas Reburning is a proven NO_x emission control technology which can be retrofitted to coal-, oil-, or gas-fired boilers. It involves the injection of reburning fuel into the region above the burners to create a fuel rich zone where hydrocarbon fragments react with NO_x to form

atmospheric nitrogen. The reburning process divides the furnace into three zones (illustrated for the wall-fired boiler in Figure 1):

- Primary combustion zone: Coal (or any other primary fuel) is fired at a rate corresponding to 75 to 85 percent of the total heat input. The stoichiometric ratio in this zone is typically limited to 1.10 (10 percent excess air). The reduced heat release and excess air limit NO_x formation.
- Reburning zone: Natural gas (normally 15 to 25 percent of total heat input) is injected higher up in the furnace to create a slightly fuel-rich zone in which NO_x is reduced. Recirculated flue gas (FGR) may be used to improve gas dispersion and mixing time. A reburning zone stoichiometry of 0.90 is optimum. Coal, fuel oil, coal-water slurry, or coke oven gas may also be used as reburning fuels. The quantity of reburning fuel can be lowered significantly when the NO_x reduction requirement is less than 60%.
- Burnout zone: In the third zone, additional combustion air (overfire air or OFA) is added to burn out any remaining fuel fragments (hydrocarbons, CO, and carbon-in-ash) and complete the combustion process. The minimum stoichiometric ratio for this zone is 1.15.

The reburning process is optimized by varying the stoichiometric ratios (SR). Typical stoichiometric ratios are, primary (SR_1) 1.10, reburning (SR_2) 0.9, and burnout (SR_3) 1.15 for the tangential- and wall-fired units using pulverized coal. For the cyclone-fired unit, the primary zone stoichiometry is 1.15 to maintain acceptable combustion and slag conditions in the cyclones.

NO_x REDUCTION

NO_x reductions as a function of gas heat input are shown in Figure 2. NO_x emissions decrease with increasing reburning fuel input (expressed as a percent of the total heat input) for all three types of units. For the tangential- and the wall-fired unit (also equipped with LNB), NO_x

emissions level off between 12 and 22% gas inputs. Lower gas input is desirable since gas is currently more expensive than coal at these stations.

Long-term NO_x data from the three Gas Reburning demonstrations are shown in Figures 3, 4 and 5. Average NO_x emissions and reductions from "as found" NO_x levels are summarized in Table 1. NO_x reductions ranged from 64 to 67% for the three sites. Gas Reburning at the tangentially fired unit resulted in NO_x reductions of 67% and 55% at gas heat inputs of 18% and 10%, respectively. For the wall-fired unit with LNB, NO_x reductions were as high as 60-65%, even at relatively low gas heat inputs (5-10%).

Title IV Phase 1 of the Clean Air Act Amendments of 1990 specifies NO_x limits for tangentially fired and wall-fired boilers of 0.45 and 0.50 lb/10⁶ Btu (or 194 and 215 g/GJ), respectively, on an annual average. Any over-compliance can be averaged with other affected units or the compliance level can be met by lowering the gas input. No similar limit for cyclone-fired units is stated.

CO EMISSIONS AND CARBON LOSSES

As shown in Figures 6 and 7, Gas Reburning reduces both CO emissions and unburned carbon-in-ash for the wall-fired unit retrofitted with LNB, from the level achieved with and without OFA. These benefits are derived from natural gas injection above the burners, which results in slightly higher upper furnace gas temperatures, and optimized OFA, which effectively mixes with furnace gas to burn out fuel combustible matter.

SO₂, CO₂, OPACITY AND PARTICULATES

Table 2 summarizes the impacts of Gas Reburning on the emissions of the tangentially fired unit. SO₂ and CO₂ emissions were reduced by 18% and 8%, respectively, at 18% gas input. These are due to part replacement of coal by natural gas, which contains no sulfur and has a lower carbon to hydrogen ratio. There was essentially no change in stack opacity or particulate matter emissions.

TABLE 1. GAS REBURNING DEMONSTRATIONS

Boiler	MWe	Location	Long-term Testing	Hours	% Gas	lb/10 ⁶ Btu	Average NOx % Reduction
Tangentially Fired	71	Hennepin, IL	Completed	1,154	Nominal 18	0.245	67
Cyclone-Fired	33	Springfield, IL	On-going	469	20-26	0.344	66
Wall-Fired	172	Denver, CO	On-going	3,019	5-19	0.260	64
				4,642			

TABLE 2. TANGENTIALLY FIRED BOILER IMPACTS

Variable	Change from Baseline	Comments
<i>Emissions</i>		
NO _x	-67% Average	With 18% gas heat input
CO	-1 to +9 ppm	At 70 and 60 MW
CO ₂	-8%	Less carbon in gas than coal
SO ₂	-18%	Zero sulfur in gas
Opacity	No change	Below 20%
Particulates	No change	Below 0.04 lb/10 ⁶ Btu (17 mg/MJ)
<i>Thermal effects</i>		
Thermal efficiency	-0.3 to -1.1%	Latent heat losses due to hydrogen
Carbon in Ash	+0.5 to 1.7%	Minimal impact on boiler efficiency
Steam temperature	No change	Controlled by attemperation
Heat distribution	Minor changes	Within normal ranges
<i>Durability</i>		
Tube wastage	No increase	Extensive ultrasonic surveys
Tube metallurgy	No change	Destructive tests of tube samples
Projected life	No change	Boiler life unaffected

TABLE 3. THERMAL PERFORMANCE OF A WALL-FIRED BOILER AT FULL LOAD

Operation	LNB	GR-LNB
Process Variables:		
Load, MWe net	148	148
Boiler exit O ₂ , % dry	3.90	3.60
Gas heat input, %	0.0	12.6
Overfire air, % of total air	0.0	19.3
Steam Side:		
Main steam temperature, °F (°C) (Design 1,005°F or 540°C)	965 (518)	992 (533)
Superheat attenuation, lb/hr (kg/h)	5,030 (2,280)	14,200 (6,440)
Hot reheat steam temperature, °F (°C)	942 (506)	985 (529)
Reheat attenuation, lb/hr (kg/h)	0 (0)	91 (41)
Economizer outlet gas temperature, °F (°C)	694 (368)	711 (377)
Thermal efficiency, %	88.00	87.55
Gross heat rate, Btu/kWh (kJ/kWh)	9,487 (10,010)	9,316 (9,828)
Net heat rate, Btu/kWh (kJ/kWh)	10,261 (10,825)	10,093 (10,648)

TABLE 4. THERMAL PERFORMANCE OF A CYCLONE-FIRED BOILER

Operation	Baseline	GR
Process Variables:		
Load MWe gross	28	29
Boiler exit O ₂ , % dry	3.78	4.12
Gas heat input, %	0	22.52
Overfire air, % of total air	7.92	28.72
Steam Side:		
Steam temperature, °F(°C) (Design 910°F or 488°C)	893 (478)	893 (478)
Attenuation heat absorption, % of total	16.17	18.89
Air heater gas inlet temperature, °F(°C)	671 (355)	672 (356)
Thermal efficiency, %	84.76	84.17

- **Objective: 60% NO_x Control**

- Exceeds that of Low NO_x Burners

- **Equipment**

- Gas injectors
- Overfire air ports

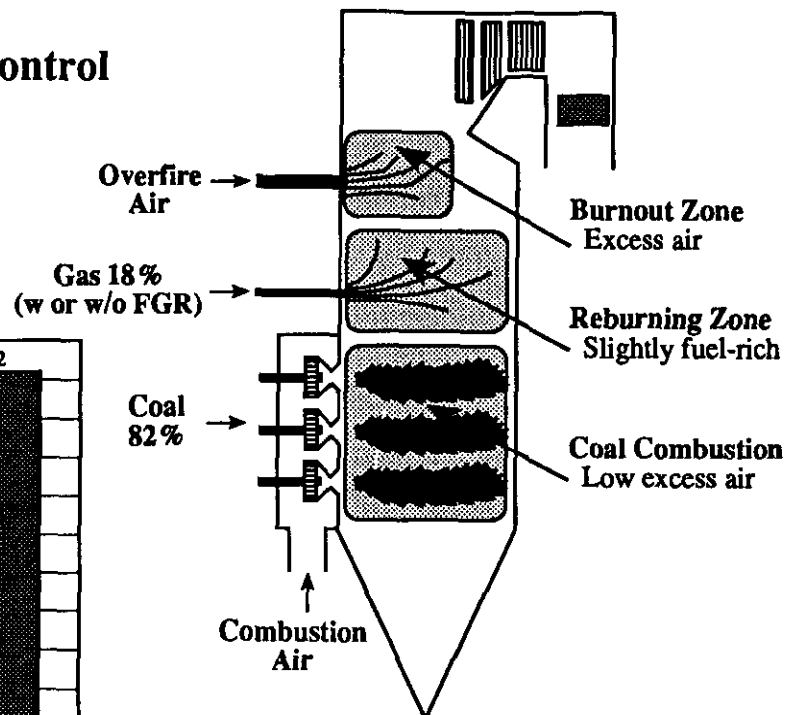
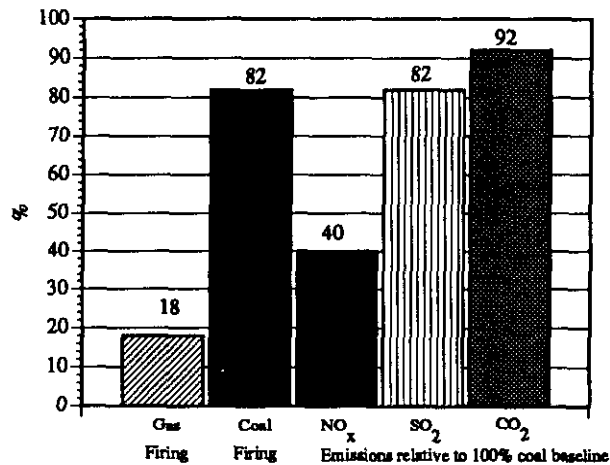


Figure 1. Gas Reburning process.

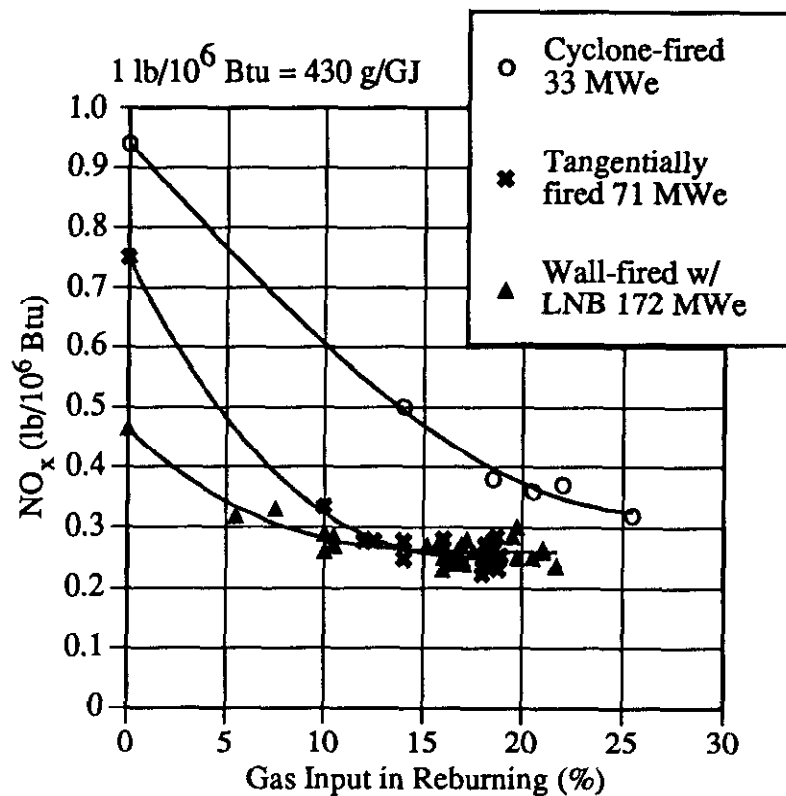


Figure 2. Gas Reburning NO_x data for three utility boilers.

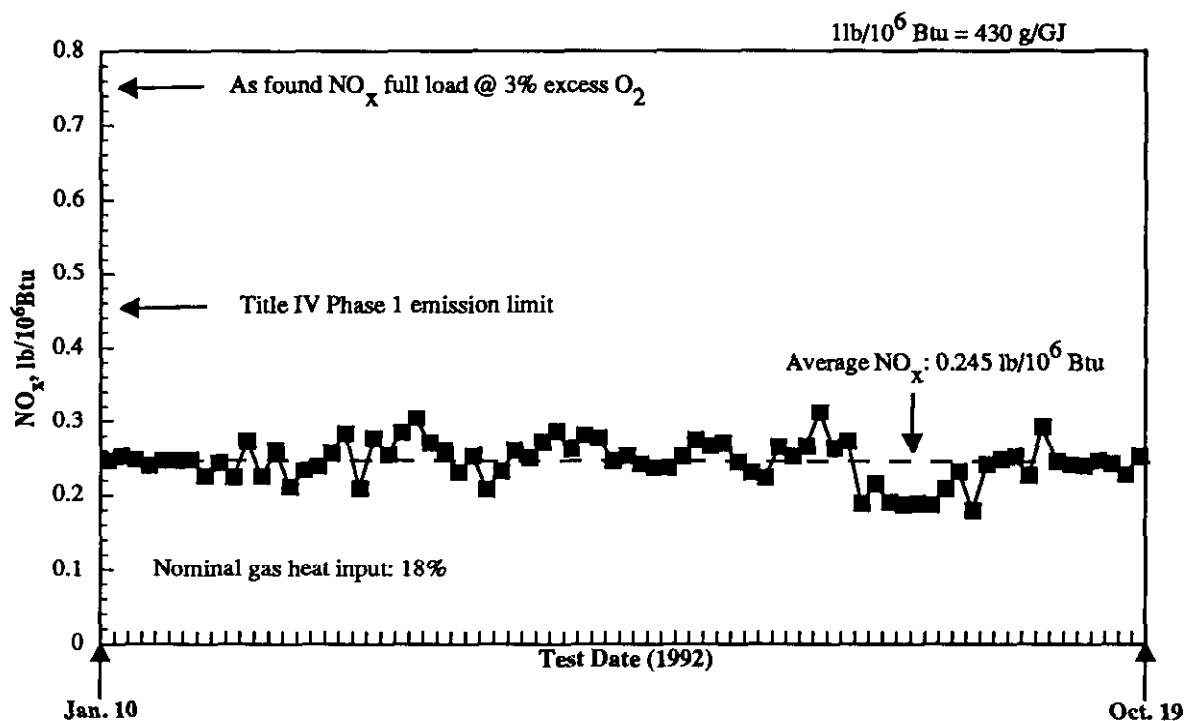


Figure 3. Long-term NO_x data for the Tangentially fired boiler.

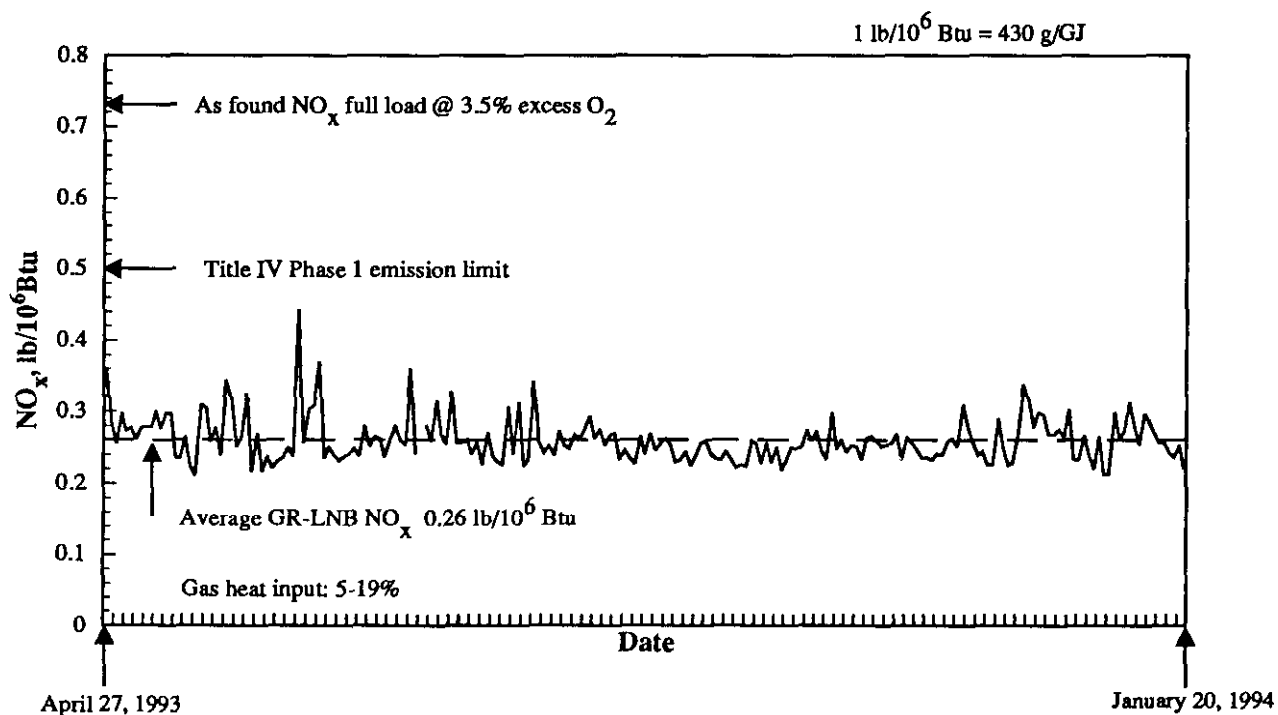


Figure 4. Long-term NO_x data for the wall-fired boiler with low NO_x burners.

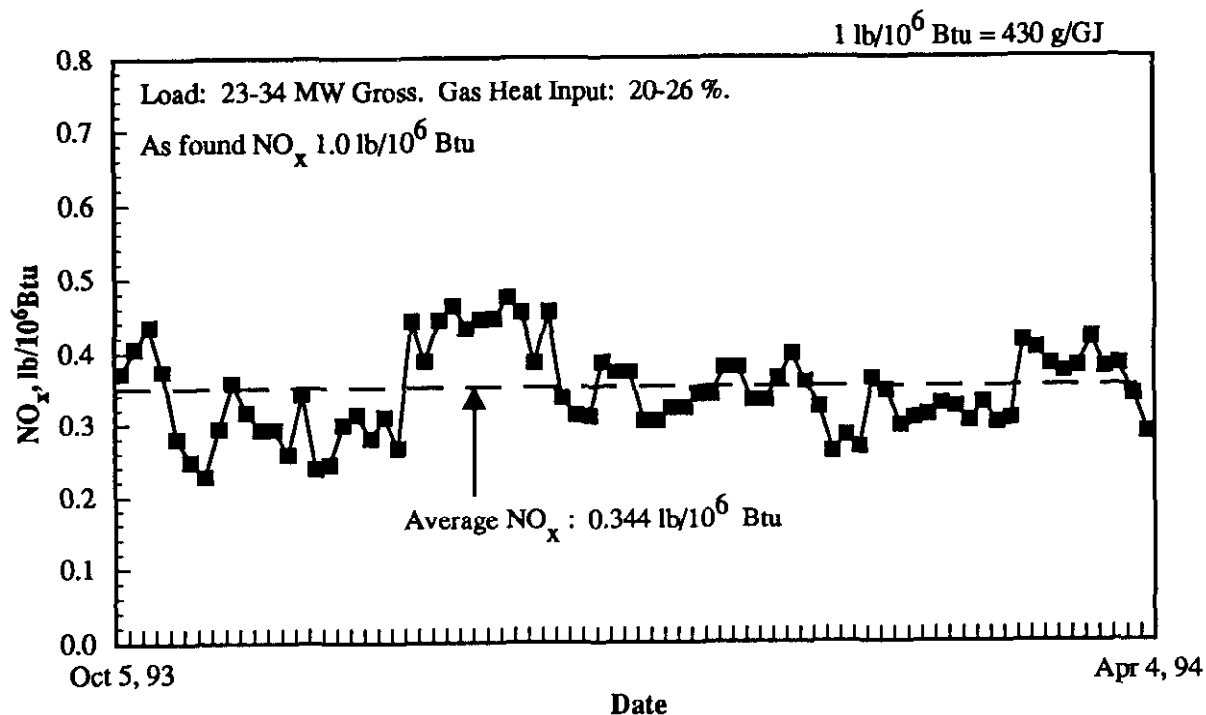


Figure 5. Long-term NO_x data for the cyclone-fired boiler.

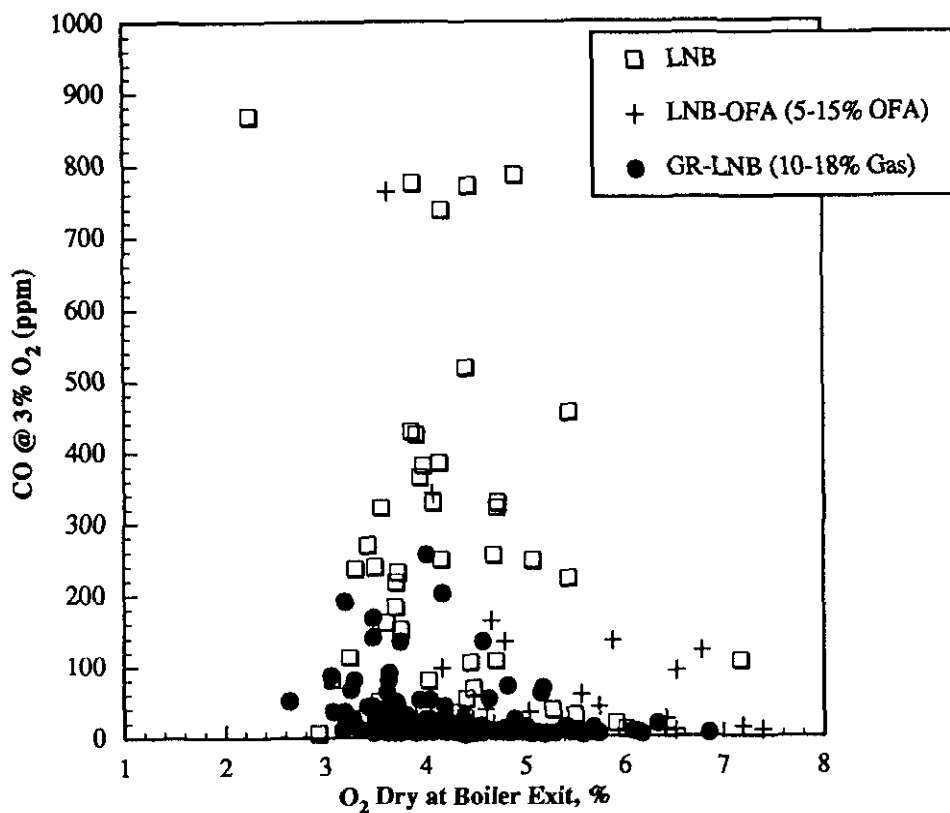


Figure 6. CO emissions as a function of boiler exit O_2 for the wall-fired boiler.

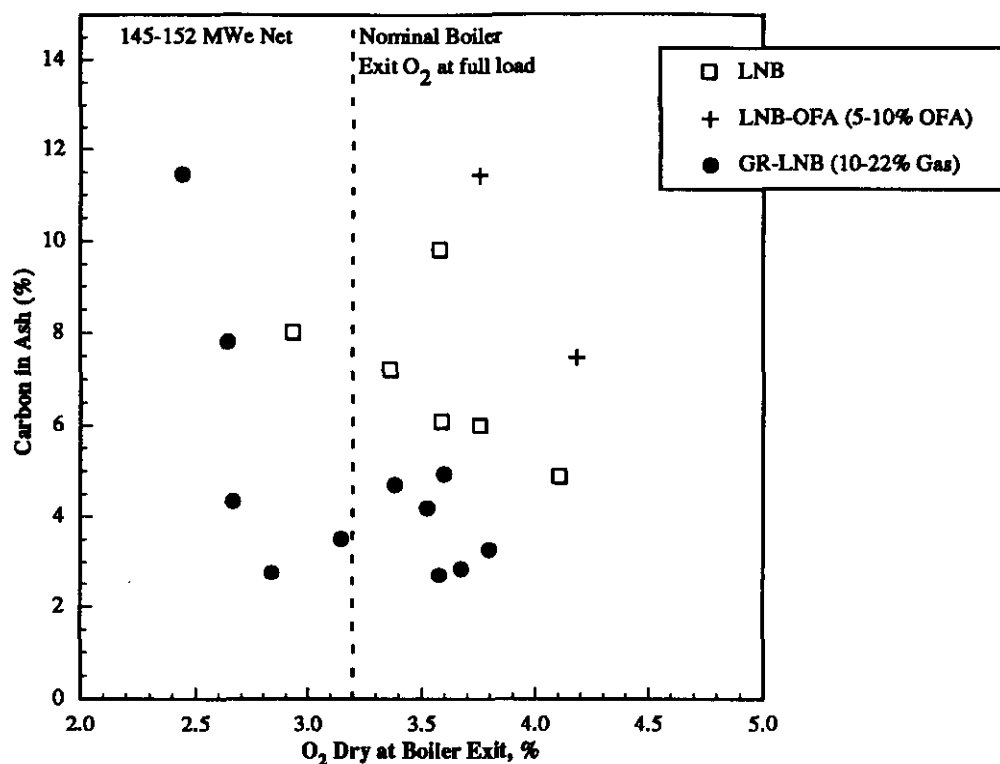


Figure 7. Carbon loss as a function of boiler exit O_2 for the wall-fired unit.

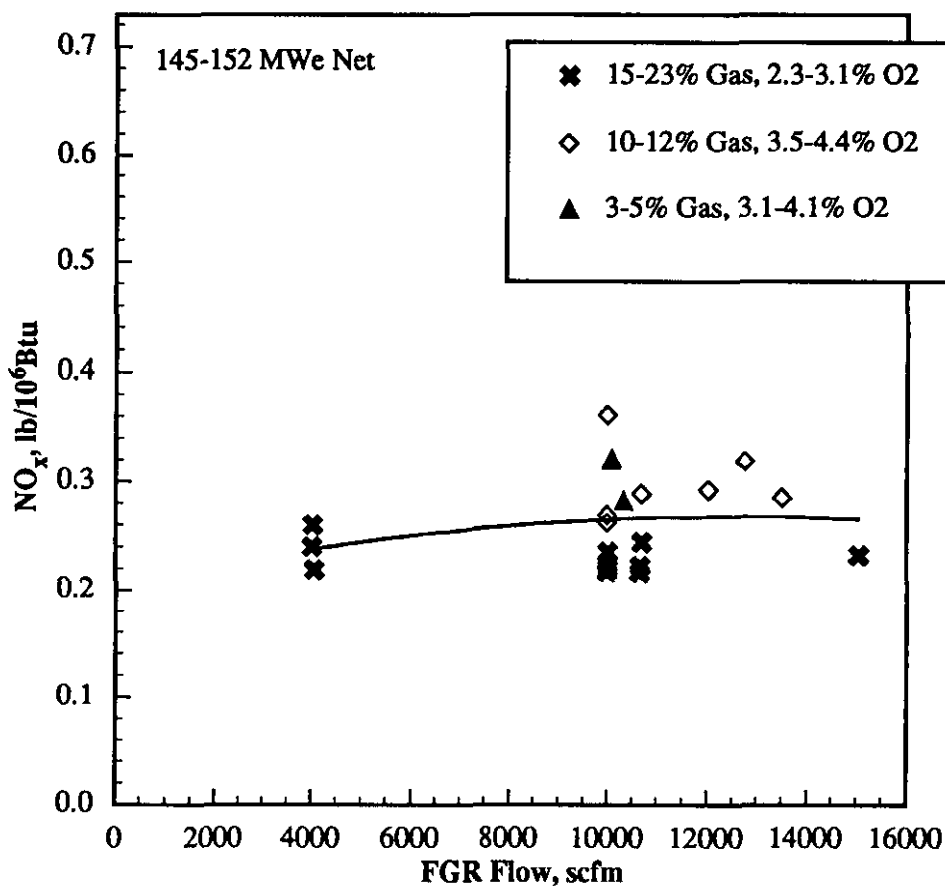


Figure 8. NO_x emissions as a function of Reburning FGR flow for the wall-fired unit.

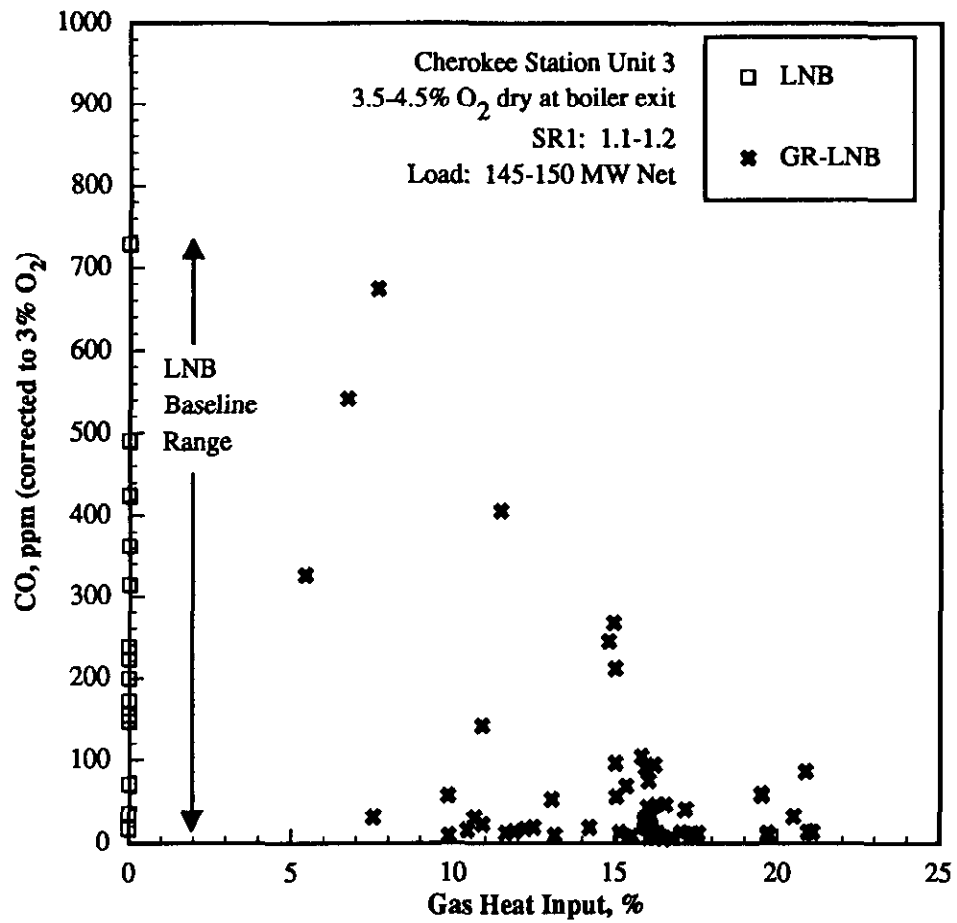


Figure 9. Effect of gas heat input on CO for the wall-fired unit.

Demonstration of Selective Catalytic Reduction (SCR) Technology for the Control of Nitrogen Oxides (NO_x) Emissions from High Sulfur Coal-Fired Boilers at Plant Crist SCR Test Facility

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ABSTRACT

This paper describes the status of the Innovative Clean Coal Technology project to demonstrate SCR technology for reduction of NO_x emissions from flue gas of utility boilers burning U.S. high-sulfur coal. The project is sponsored by the U.S. Department of Energy, managed and co-funded by Southern Company Services, Inc. on behalf of the Southern Company, and also co-funded by the Electric Power Research Institute and Ontario Hydro; and is located at Gulf Power Company's Plant Crist Unit 5 (75 MW tangentially-fired boiler burning U.S. coals that have a sulfur content near 3.0%), near Pensacola, Florida. The test program will be conducted for approximately two years to evaluate catalyst deactivation and other SCR operational effects. The SCR test facility has nine reactors: three 2.5 MW (5000 scfm), and six 0.2 MW (400 scfm). Eight reactors operate on high-dust flue gas, while the ninth reactor draws gas from the exit of the Unit's hot side precipitator. The reactors operate in parallel with commercially available SCR catalysts obtained from vendors throughout the world. Long-term performance testing began in July 1993. Test facility description and test plans, as well as operational issues and preliminary test results are reported in this paper.

INTRODUCTION

The need within the utility industry for detailed information on Selective Catalytic Reduction (SCR) technology has never been greater. The 1990 Clean Air Act Amendments (CAAA) create two new nitrogen oxide (NO_x) control requirements on fossil fuel-fired utility boilers. First, Title IV of the CAAA regarding acid rain requires that emission limits be placed on all coal-fired utility boilers in two phases, one beginning in 1995 and the other in the year 2000. SCR,

in which ammonia is added to the flue gas to reduce NO_x to nitrogen over a catalyst, is not as prominently mentioned as low NO_x burner technology for meeting the Title IV provisions. However, the final EPA emission limitations for each of the two phases remain to be established, and SCR is still very much under consideration in utilities' compliance strategies. Second, Title I of the CAAA addresses attainment of the ambient air quality standards. Regarding ozone, Title I calls for certain areas presently not in attainment to consider NO_x controls to achieve attainment. As a result, renewed focus has been placed on advanced NO_x control technologies such as SCR, which may be required to meet compliance requirements for ozone non-attainment areas.

SCR technology involves the injection of ammonia into flue gas and then passing the gases through one or more catalyst layers where NO_x and ammonia react to form nitrogen and water vapor. A simplified, typical SCR process installation for a utility boiler is depicted in Figure 1. Hot flue gas leaving the economizer section of the boiler is ducted to the SCR reactor. Prior to entering the reactor, ammonia (NH₃) is injected into the flue gas at a sufficient distance upstream of the SCR reactor to provide for complete mixing of the NH₃ and flue gas. The quantity of NH₃ is adjusted to achieve the desired NO_x removal efficiency. The reactions between NH₃ and NO_x occur as the flue gas passes through the catalytic layers of the SCR reactor. Ductwork is installed to bypass some flue gas around the economizer during periods when the boiler is operating at reduced load. This is done, especially on retrofits, to maintain the temperature of the flue gas entering the catalytic reactor at the proper reaction temperature of about 700°F.

SCR technology is in commercial use in Japan and Western Europe on gas-, oil-, and low-sulfur coal-fired power plants. There are now over 36,000 MW of fossil-fuel-fired SCR capacity in Japan, including 6,200 MW on coal. There are over 33,000 MW of fossil-fuel-fired SCR capacity in Western Europe, including 30,500 MW of coal-fired capacity.¹

SCR DEMONSTRATION GOALS

Although SCR is widely practiced in Japan and Western Europe, numerous technical uncertainties are associated with applying SCR to U.S. coals. These uncertainties include:

- (1) potential catalyst deactivation due to poisoning by trace metal species present in U.S. coals but not present, or present at much lower concentrations, in fuels from other countries;
- (2) performance of the technology and effects on the balance-of-plant equipment in the presence of high amounts of SO₂ and SO₃ (e.g., plugging of downstream equipment with ammonia-sulfur compounds); and
- (3) performance of a wide variety of SCR catalyst compositions, geometries and manufacturing methods at typical high-sulfur coal-fired utility operating conditions.

These uncertainties are being explored by constructing and operating a series of small-scale SCR reactors and simultaneously exposing different SCR catalysts to flue gas derived from the combustion of high-sulfur U.S. coal. The first uncertainty will be handled by evaluating SCR catalyst performance for two years under realistic operating conditions found in U.S. pulverized-coal-fired utility boilers. Deactivation rates for the catalysts exposed to flue gas of high-sulfur U.S. coal will be documented to determine catalyst life and associated process economics. The second uncertainty will be explored by performing parametric tests, during which SCR operating conditions will be adjusted above and below design values to observe deNO_x performance and ammonia slip. The performance of air preheaters installed downstream of the larger SCR reactors will be observed to evaluate the effects of SCR operating conditions upon heat transfer and boiler efficiency. The third uncertainty is being addressed by using honeycomb- and plate-type SCR catalysts of various commercial compositions from the U.S., Japan, and Europe. Tests with these catalysts will expand knowledge of the performance of SCR catalysts under U.S. utility operating conditions with high-sulfur coal.

The intent of this project is to demonstrate commercial catalyst performance and to determine optimum operating conditions and catalyst life for the SCR process. This project will also demonstrate the technical and economic viability of SCR while reducing NO_x emissions by at least 80%.

SCR TEST FACILITY DESCRIPTION

The SCR demonstration facility is located at Gulf Power Company's Plant Crist in Pensacola, Florida. The facility treats a flue gas slip-stream from Unit 5, a commercially operating 75-MW unit, firing U.S. coals with a sulfur content near 3.0%. Unit 5 is a tangentially-fired, dry bottom boiler with hot- and cold-side electrostatic precipitators (ESPs) for particulate control. The SCR test facility consists of nine reactors operating in parallel for side-by-side comparisons of commercially available SCR catalysts obtained from vendors throughout the world. With all reactors in operation, the amount of combustion flue gas that can be treated is 17,400 scfm or 12% of Unit 5's capacity (about 8.7 MWe).

The process flow diagram for the SCR test facility is shown in Figure 2. There are three large SCR reactors (2.5 MW, 5000 scfm) and six smaller SCR reactors (0.2 MW, 400 scfm). Eight of the nine reactors operate with flue gas containing full particulate loading (high dust) extracted from the inlet duct of the hot-side ESP, while one small reactor uses flue gas fed from the ESP outlet (low dust).

Each reactor train has electric duct heaters to control the temperature of the flue gas entering the reactor and a venturi flow meter to measure the flue gas flow. An economizer bypass line to the SCR test facility maintains a minimum temperature of 620°F for flue gas supplied to the test facility. Anhydrous ammonia is independently metered to a stream of heated dilution air that injects the ammonia via nozzles into the flue gas stream prior to each SCR reactor. The flue gas and ammonia pass through the SCR reactors, which have the capacity to contain up to four catalyst layers.

For the large reactor trains, the flue gas exits the reactor and enters a pilot-scale air preheater (APH). The APHs are incorporated in the project to evaluate the effects of SCR reaction chemistry on APH deposit formation and the effects of the deposits on APH performance and operations. All reactor trains, except the low-dust train, have a cyclone downstream of the SCR reactor to protect the induced draft (ID) fans from particulates. The exhaust for all the SCR reactors is combined into a single manifold and reinjected into the host boiler's flue gas stream ahead of the cold-side ESP. The preheated air from the APH on the large reactors is also combined into a single manifold and returned to the host boiler draft system at the air outlet of the existing APH. All of the particulates that are removed from the flue gas with the cyclones are combined and sent to an ash disposal area.

CATALYST TESTING PLANS

Six catalyst suppliers are participating in this project, providing eight different catalysts. The two suppliers from Europe and two from Japan provide one catalyst each. The two U.S. firms are supplying four of the catalysts. The catalysts being evaluated represent the wide variety of SCR catalysts being offered commercially and possess different chemical compositions and physical shapes. Of these eight catalysts, five have a honeycomb geometry while the remaining three are plate-type catalysts. The suppliers, corresponding reactor size, and catalyst configuration are listed in Table 1.

After start-up, the baseline performance of each catalyst was determined at design conditions which are being maintained for the two year test period. Once baseline performance was established, each reactor was sequenced through a test matrix (parametric tests) that varied the following variables around the SCR process design point: ammonia-to-NO_x ratio, temperature, and space velocity. Space velocity is the ratio of flue gas volumetric flow rate to catalyst volume. With a fixed catalyst volume, variations in flue gas flow rates alter the space velocity around the design point.

DeNO_x efficiency, pressure drop, SO₂ oxidation, and ammonia slip are determined at each parametric test condition. After each parametric test matrix has been completed, each reactor is returned to baseline design conditions. This allows for steady-state operation over a three month period between parametric tests for aging of the catalyst. The parametric test matrix is repeated every four months for each reactor train. When not under parametric testing, the reactors are normally operated at baseline conditions.

The operating parameter ranges to be examined during the parametric tests and the long-term design conditions (baseline) are as follows:

	<u>Minimum</u>	<u>Baseline</u>	<u>Maximum</u>
Temperature, (°F)	620	700	750
NH ₃ /NO _x molar ratio	0.6	0.8	1.0
Space velocity, (% of design flow)	60	100	150
Flow rate, (scfm)			
-large reactor	3000	5000	7500
-small reactor	240	400	600

PROJECT SCHEDULE AND STATUS

The demonstration project is organized into three phases. Phase I consisted of permitting, preparing the Environmental Monitoring Plan and preliminary engineering. Phase II included detailed design engineering, construction, and start-up/shakedown. Detailed design engineering began in early 1991 and concluded in December, 1992. Construction began at the end of March 1992 and was completed by the end of February 1993. Start-up/shakedown concluded in June 1993. Baseline commissioning tests without catalysts were conducted through June. The loading of all catalysts was completed at the end of June.

The operations phase for process evaluation, Phase III, commenced in July 1993. The process evaluation will last for approximately two years and will be followed by preparation of a final report, which will include process economic projections. The major milestones on the schedule are shown in Table 2.

OPERATIONAL ISSUES

Air Preheaters

The three pilot sized air preheaters were included in the design to evaluate the impacts of SCR on the balance of plant equipment. Three different air preheater designs are being demonstrated: a standard three layer bisector Ljungstrom* design, an experimental two layer bisector Ljungstrom* design, and a heat-pipe, all supplied by ABB Air Preheater, Inc. of Wellsville, New York. All three are the smallest commercially available, with modifications to better simulate conditions present in larger (more normally sized) air preheaters. Both of the rotary air

preheaters have variable speed drum motors to allow the baskets to experience greater temperature swings as the plates are exposed for longer periods to the gas and to the air. The normal rotational speed has been set to mimic the temperature swings of a 30 foot diameter drum.

The rotary air preheaters are equipped with sootblowers on both the top and bottom of the drums. The sootblowers are fixed rakes with several nozzles that blow simultaneously. During sootblowing, the drum speed is increased to better model the sootblowing effects. The heat-pipe is equipped with five layers of rotary sootblowers with approximately four feet of finned pipes between sootblowers. Our experience has shown that the heat-pipe sootblowers are extremely effective in maintaining pressure drop across the air heater. However, the rotary air preheaters have not fared as well. The rotary air preheaters were fouled early during a high slip condition, with aggressive sootblowing improving the fouling only slightly. The sootblowing schedule for the rotary air preheaters is two passes every four hours, with the gas outlet temperature held at 300°F.

In late May, the rotary air preheaters were disassembled and inspected to identify the causes of the fouling and to locate the temperature region where any condensation or precipitation occurs. During the inspection, baskets loaded with plates of different metals and coatings were installed for corrosion evaluations. After the new baskets were installed, the air preheaters were high pressure washed with 3500 psi water to reduce the pressure drops. The drain from the wash water was sampled and will be analyzed. The three-layer design air preheater was returned to "like-new" pressure drops, while the two layer design air heater's wash was complicated by an interference with a sootblower nozzle and the high pressure wash head. This interference did not allow a perpendicular jet of water to enter the air preheater baskets and shielded some deposits. As a result, the two layer air preheater was not returned to a "like-new" condition. This air heater was later plagued by a failure of the lower sootblower. In less than a month, the pressure drop had increased from 5 inches to over 13 inches (w.c.) before the repair parts arrived for the lower sootblower. After the air preheater sootblower was returned to service, the heater was extensively sootblown and the pressure drop was reduced to less than 7 inches. Subsequent high pressure washes have improved the pressure drop, but it has not returned to original performance.

Reactor Fouling and Sootblowing

After only a few hours of operation during its initial start-up after catalyst loading, the low-dust reactor experienced severe plugging of the first catalyst layer. While the large reactor bypass lines may be used to flush any ash accumulations associated with the main extraction scoop, the low dust reactor ductwork was not provided with any bypass capability. In addition, the isolation damper for that line is approximately 100 feet downstream of the scoop allowing a deadleg for sulfate formation when the reactor is off-line. Thus, during start-up and unusually large amount of solid material may have been introduced to the low-dust reactor. The first layer purge dampers were relocated to minimize the deadleg, and the reactor heater was uprated and moved to just downstream of the isolation damper, so the piping could be slowly warmed while drawing flue gas. Unfortunately, the extra length of higher temperature piping radiated more

heat than was originally predicted and an additional heater was installed in the original location to help maintain reactor temperature.

In addition to fouling problems in the low-dust reactor, some fouling of other reactor dummy beds has occurred. This was primarily caused by an ash mud formed due to moisture condensing from the humid coastal air while the reactors were off line for extended periods.

During normal operation, the reactor pressure drops do slowly increase, but are usually controlled by sootblowing once per shift. The large reactors are equipped with retracting lances with a perpendicular array of nozzles mounted that blow steam across the catalyst as the lance traverses across the reactor. The small reactors are blown by air lance inserted through a ball valve installed above each basket layer. One vendor's catalyst was damaged by sootblowing. Subsequent discussions with the vendor revealed that the catalyst was not designed for routine sootblowing and in the future the catalyst should be operated without sootblowing. Another vendor expressed some concern about the frequency of sootblowing. We are experimenting with and evaluating sootblowing effects and optimum frequency.

Dilution/Extraction Gas Sampling/Monitoring System

The SCR gas analyzer system was supplied by Lear Siegler Measurement Controls Corporation (LSMCC), now Monitor Labs, Inc. of Englewood, Colorado. The system consists of thirteen (13) dilution/extraction probes for the measurement of NO_x, CO, CO₂, and SO₂. The system uses Yokagawa in-situ probes for the measurement of oxygen. There are twenty-six (26) Yokagawa oxygen probes. Normal dilution ratios on the dilution/extraction components of the system range from 30/1 to 250/1. NO_x analysis is performed using an LSMCC ML8840 chemiluminescence NO_x analyzer with a detection limit of 2 ppb resulting in a flue gas detection limit of approximately 0.25 ppm. CO is measured using a LSMCC model ML8830 infrared CO analyzer with a detection limit of 0.1 ppm resulting in a flue gas detection limit of approximately 3 ppm. CO₂ is measured using a Siemens Ultimat 5E non-dispersive infrared CO₂ analyzer. SO₂ is measured using a LSMCC model ML8850 fluorescence SO₂ analyzer with a detection limit of 1 ppb resulting in a flue gas detection limit of 0.1 ppm. Oxygen is measured using in-situ zirconium oxide cell technology.

Early in the project, several anomalies were investigated relating to the gas analyzer data. In addition to problems with the dilution probes, analyzers, and data collection equipment, significant dilution effects due to air in-leakage into the reactor were also creating apparent data anomalies. The NO_x concentration inputs for automatic ammonia injection were taken from the inlet ductwork to the pilot plant, rather than from the ammonia injection point. Therefore, air in-leakage after the sample point decreased the NO_x concentration at the ammonia injection point. This skewed the calculation for ammonia injection rate and resulted in a higher than expected ammonia-to-NO_x ratio. Of course, the ammonia injection rate can easily be corrected by material balance to compensate for oxygen in-leakage. This however, links a large number of continuous measurements to the calculation, resulting in frequent errors when one of the measurement points is not operating correctly. To avoid similar problems in the future, NO_x readings should be taken close to the ammonia injection point, rather than upstream of potential in-leakage sources.

Ammonia Flow Control and Usage

The ammonia vapor flow rates for injection into the reactors are being controlled by precision mass flow control valves. These controllers are affected by liquid in the flow stream, pressure variations, piping debris, and the orientation of the controller itself. These controllers were calibrated on nitrogen and scaled to read ammonia flow. Although initial results indicated accurate flow control, subsequent measurements indicated that actual ammonia flow was 10 to 25 percent higher than indicated by the controller. Actions taken to correct this situation include installation of coalescent filters on the ammonia supply line to each control valve, reorientation of the controllers, replacement of the ammonia header pressure regulator, cleaning of each controller, recalibration and verification with other instruments, and eventual replacement of the large reactor controllers with a different vendor's offering.

At design NO_x reduction of 80%, ammonia usage is averaging five pounds of liquid ammonia per megawatt per day. This requires that the ammonia storage tank be refilled on a monthly basis.

Ash Consistency

In general, fly ash has not been a significant problem in the pilot plant. However, ash characteristics have affected the testing and gas sampling equipment. We are undergoing studies to determine the interactions between fly ash, ammonia, and ammonia-sulfur compounds, particularly around the air preheaters. The fly ash is extremely hygroscopic and exposure of the dry fly ash to humid air often results in fouling problems.

Start-ups & Shut-downs

The SCR reactors are purged prior to shut-down to eliminate any ammonia or sulfur radicals that may condense or precipitate as the reactor is cooled. This is accomplished by using the reactor electric heaters and the air purge dampers upstream of the heaters. This would not be duplicated in a full size system due to the cost of heating purge air, but has been effective in the test facility in avoiding some of the plugging problems noted in other test facilities. Our experience has shown that there is enough thermal mass in the catalyst materials that excessive temperature swings are nearly impossible. Unless an SCR equipped boiler is using oil for start-ups, it would seem reasonable to warm the reactor while the back-end ductwork is warming up, although doing so before building enough temperature in the air preheaters to sustain a coal fire would slow that process in start-up. Most full size SCR systems do have a bypass that would isolate the reactor from the flue gas, and this bypass is needed more for catalyst protection during an eventual boiler leak, especially an economizer leak that would be pouring liquid water into the flue gas. But under normal shut-downs that don't use oil for flame stabilization, allowing the flue gas and the boiler purge air to flow through the reactor to purge the reactor and cool the catalyst is recommended. It is possible after purging enough reactor volumes of air through the catalyst, that it could then be bypassed and the residual heat be bottled up in the reactor preventing condensation of the ambient air's humidity.

START-UP AND COMMISSIONING TEST RESULTS

The facility test plan is divided into two main sections, 1) start-up and commissioning tests, and 2) long term testing and parametric evaluation. The start-up and commissioning tests were designed to insure the quality of data obtained from the facility. These tests included base-line evaluations as well as measurements insuring comparability between the reactors. The initial testing and data evaluation has been completed. The following list describes some of the start-up and commissioning tests that were performed.

- (1) Instrument calibration and gas analysis system verification.
- (2) Base-line particulate concentration, size distribution, and metals concentrations from host unit.
- (3) Base-line chemical composition of host unit slip stream.
- (4) Comparative particulate loading to each reactor.
- (5) SO₂ oxidation characteristics of the system.
- (6) Determination of inherent system ammonia oxidation characteristics.
- (7) Verification of ammonia mass flow control.
- (8) Measurement of catalyst SO₂ oxidation characteristics.
- (9) Determination of velocity and particulate profiles at reactor exits.

The following tables and discussions describe some of the most important start-up and commissioning test results. Several analyses such as particle size distributions and metals analyses are not presented at this time due to their length. These will be shown in the published project quarterly reports and in the final project report.

Base-Line Flue Gas Composition

Table 3 shows the base-line flue gas composition measured in the host unit duct at high (84 MW) and low (43 MW) boiler load. This data compares favorably with data taken several years ago during initial site selection.

Reactor Particulate Loading

Particulate loading in the process stream is a critical design consideration in the development of SCR catalysts. Initial particulate measurements showed that the small reactors were receiving a higher particulate loading than the large reactors under all boiler conditions. After reviewing the design of the splitting section of the main flue gas scoop at the point of the small reactor take-off, the splitting section was mechanically improved to give proper isokinetics, which corrected the particulate loading discrepancies between the reactors. Table 4 gives the particulate loading to each of the eight high dust test facility reactors at high and low boiler load. This data was taken using isokinetic particulate sampling performed as a traverse across the cross-section of the reactor exits. This data compared favorably with the base-line particulate data taken from the host unit duct work.

The data in Table 4 show that the particulate loading to each reactor is fairly consistent and that the loading does not vary more than 10% from the average in most cases. Some of the

differences in loading are likely due to boiler variations since individual measurements were taken over a very short period of time with the overall tests taking several weeks. More particulate data will be obtained as the testing program continues. This should allow long term loading characteristics to be established for each reactor.

Particulate and Velocity Distributions

Tests have also been performed to determine how evenly the particulates are distributed within the individual reactors. These tests were performed at the reactor exits. Preliminary results indicate that the mass loading is evenly distributed in the cross-sections of the reactors. These measurements were made as six point traverses over the cross-section of the large reactors and three point traverses over the cross-section of the small reactors. Velocity distribution measurements across the reactors at the same sampling locations also indicate a very even velocity distribution.

Sulfur Dioxide Oxidation

Sulfur trioxide in the flue gas stream is an extremely important consideration for balance of plant equipment in SCR applications. This is primarily due to the side reaction of SO_3 with ammonia. This reaction forms ammonium bisulfate/sulfate which occur at relatively low temperatures downstream of the SCR reactor, e.g., at the air preheater. SCR catalysts have the potential to oxidize SO_2 to SO_3 thereby exacerbating the ammonium bisulfate/sulfate formation problem as well as contributing to acid deposition problems.

To characterize this oxidation, two series of start-up and commissioning test were performed. The first series of tests characterized the inherent SO_2 oxidation within the test facility system. This included oxidation across the test facility flue gas heaters, as well as oxidation across the reactors themselves (without catalyst). These tests were performed on one large reactor and one small reactor. The results are shown in Table 5. The heater inlet SO_3 values compare favorably with the base line values at low load. However, the high load values for SO_3 appear to be considerably lower than base line. This may be due to changes in boiler operation between testing periods (several months). The data show that no net increase in SO_3 was taking place across the SCR reactors. In fact, a slight decrease in SO_3 was noted, which was probably due to deposition in cool spots on the reactor between measurement points. Some oxidation was noted across the flue gas heaters, which was expected. The absolute increase in SO_3 over the heaters was greatest at low load. This may be due to the higher heat flux required from the heaters at low unit load to maintain temperature to the SCR reactors. However, the percent increase in SO_3 across the heater at both high and low load is roughly equivalent. The second series of SO_2 oxidation tests will determine the oxidative characteristics of the SCR catalysts themselves. These tests were performed as part of the preliminary parametric sequence, and all catalyst met or exceeded the specification.

Upon completion of commissioning tests without catalyst, catalyst loading was completed in late June 1993. Long-term testing and parametric evaluations are underway. Immediately after catalyst loading, all reactors were operated briefly to obtain fly ash samples for the Toxicity Characteristics Leaching Procedure (TCLP) analysis. The TCLP results indicated no detectable

amounts or change in constituents between baseline ash samples and ash samples from the SCR process outlet.

PARAMETRIC AND LONG TERM TEST RESULTS

The preliminary parametric test sequence as well as the first full parametric sequence have now been completed. In general, all catalysts met or exceeded the basic design criteria. However, significant differences have been noted between the catalysts in terms of both physical and chemical characteristics.

Flue Gas Composition

The flue gas composition over the testing period July through December, 1993 is shown in Table 6. This data represents data acquired on a continuous basis using the SCR gas analysis system. The table shows the gas concentrations in terms of average values, average high values, and average low values over the reporting period. This semi-annual data was determined using daily averages, daily highs, and daily lows during periods that the host boiler was on-line (operating at greater than 40 MWe).

Air Preheater Performance Data

As discussed, the three large reactors of the SCR facility are each equipped with an air preheater. Table 7 shows the average operating parameters for the three air preheaters over the reporting period shown.

The original design of the SCR facility included air preheater bypass ducting which allowed the air preheaters to be bypassed during any condition other than normal operating conditions. This was done to insure that the air preheater's long-term fouling characteristics were not skewed by extreme conditions during some of the short term parametric tests. The large reactor fan design requires relatively cool gas (less than 350°F). To accommodate this restriction, the air preheater bypass ducting was equipped with heat exchangers which were designed to cool the flue gas in place of the air preheaters. Unfortunately, the design of the by-pass heat exchangers caused immediate fouling upon use, making them unsatisfactory for the application. Consequently, the SCR facility is forced to use the three large reactor air preheaters at all times when on-line to maintain proper flue gas conditions for the large reactor fans. As a result, the air preheaters are exposed to the harsh conditions created by some of the parametric tests. However, these test periods are very short compared to the overall operating time at standard conditions, and it is assumed that overall fouling characteristics of the air preheaters are not greatly affected by the current operational requirements. The data shown in Table 7 includes any parametric test conditions that were performed during the specific time period.

Reactor Baseline Performance Data

Tables 8 and 9 show the performance of the catalysts at or near the design operating conditions of 0.8 ammonia-to-NO_x ratio, 5,000 SCFM flow rate, and 700° F reactor temperature. As can

be seen in the tables, the actual measured ammonia-to-NO_x ratio is greater than 0.8. This is primarily the result of some miscalibrations in both flow rate and ammonia injection rate, creating a higher than desired ammonia-to-NO_x ratio. This higher ratio, however, has one beneficial effect in that it creates ammonia slip values that are well within the ammonia sampling method detection range, allowing for improved kinetics analyses.

Sulfur Dioxide Oxidation Data

The percent of sulfur dioxide oxidation by the catalyst is shown in Table 8. This data has been corrected for heater oxidation as well as normal SO₃ loss through the reactor. Predicted normal loss of SO₃ is based on the data shown in Table 5 which was generated during initial commissioning tests without catalyst present. Reactor inlet SO₃ is not measured simultaneously with outlet SO₃, rather it is estimated from historical values correlated to boiler load and reactor operating temperature.

Ammonia Slip Data

Table 9 shows the baseline ammonia slip values for the catalysts. Slip values measured at 0.8 ammonia-to-NO_x ratio are often near or below detection limits. Note that the ammonia-to-NO_x ratio is somewhat greater than 0.8, as previously discussed. Slips within the detection limits allow for more accurate comparisons between catalysts and also allow for more accurate reactor modeling to be performed. Slip measurements are made by traversing the reactor exits at points similar to the particulate testing.

SUMMARY

During this ICCT demonstration, performance data will be developed to evaluate SCR capabilities and costs that are applicable to boilers using high-sulfur U.S. coals. The SCR demonstration facility construction has been completed and start-up/shakedown was finished in early June 1993. Long-term performance testing began in July 1993 and will be completed in 1995.

In general, the start-up and commissioning tests have demonstrated that each of the SCR reactors is operating on the same basis in terms of process gas feed. Distribution measurements on the individual reactors are in good agreement with the original design requirements. The results of these tests validate the test facility and guarantee the quality of data obtained in long-term operation and parametric testing.

Operational issues which have been successfully addressed include resolving sulfate deposition in the ammonia injection header system, adding extra sootblower ports to clean areas of ash accumulation, improvements on steam sootblowing of large reactors and air preheaters, and resolving several fan operational issues. Problem areas still being addressed include operation of sampling/monitoring systems, low dust reactor fouling and bypass heat exchanger operation. Several of the operational issues such as fouling by ash and ammonium bisulfate are controllable by sootblowing. Plugging of the ammonia injection nozzles has been eliminated by preheating

the dilution air. Also, the catalyst remains relatively unaffected by the effects of tube leaks in the steam generator and by proper purging during shutdowns.

Early results of the parametric and long-term testing show that all the catalysts meet or exceed the specifications of ammonia slip, SO₂ oxidation, and NO_x reduction. However, the catalysts show major differences in their operating characteristics in terms of both physical operation and chemical activity. No significant loss in activity has been noted in the catalysts to date. Continued aging of the catalyst should allow extrapolation of the catalyst life as well as determination of the primary poisons in the coals currently being used at the test facility.

ACKNOWLEDGEMENT

We would like to thank the Southern Research Institute on-site team for their significant contribution in obtaining the data presented here; Mr. Robert Heaphy, Mr. James Garrett, Mr. Randy Hinton, and Mr. Richard Jacaruso. We would also like to thank Mr. James Gibson of Spectrum Systems, Inc. for his diligent efforts in maintaining the SCR gas analyzer system and for his efforts in assuring data quality. Special thanks go to Mr. Gerald Bandura (SCS Engineering) and Mr. Danny Mabire (ICS) for their constant efforts in maintaining the instrumentation and controls for the test facility as well as maintaining and programming the digital control system. Our sincere thanks also go to Mr. Bill Zimmer for his unfailing efforts in maintaining the huge quantities of data acquired from the test facility.

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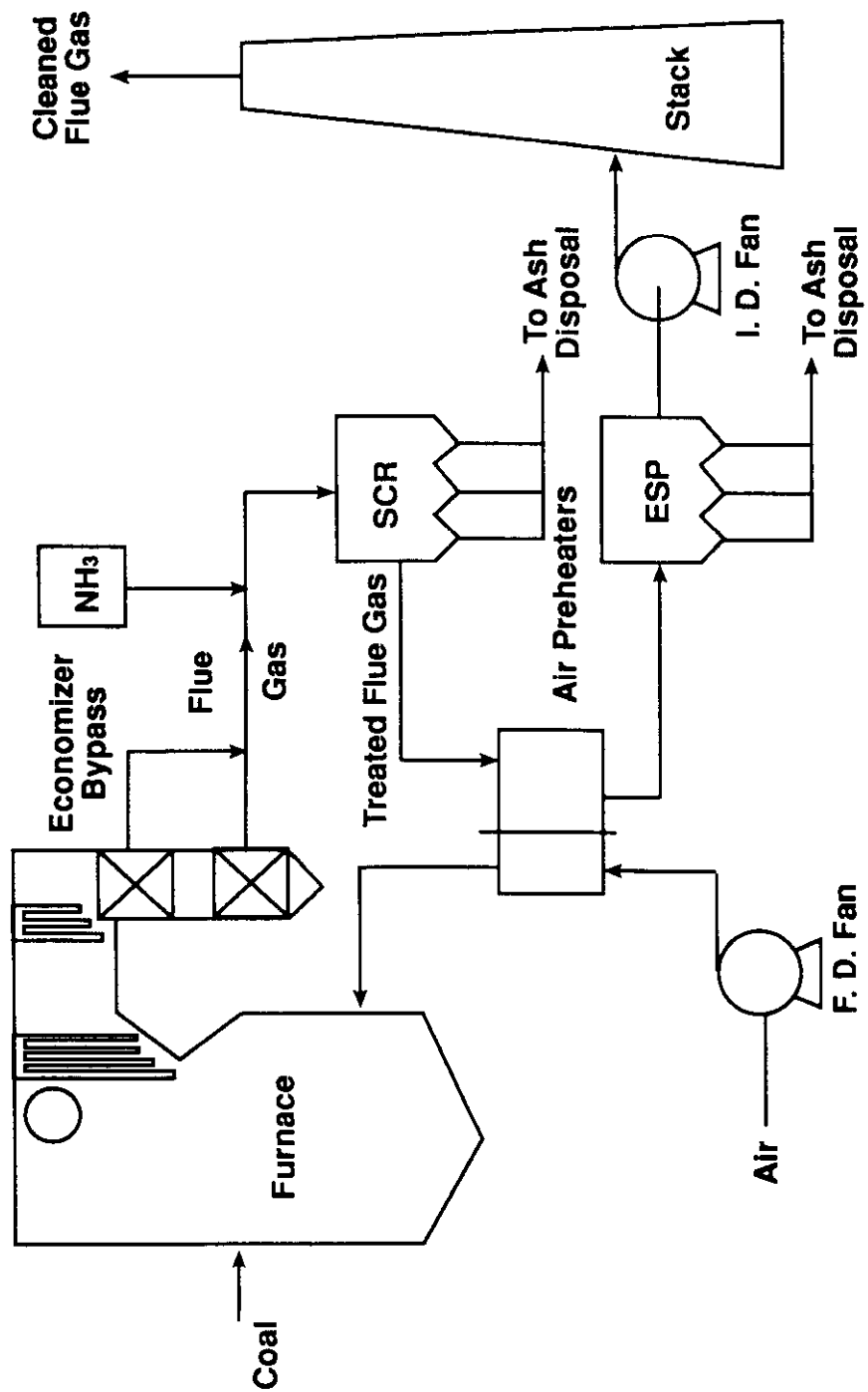


Figure 1. Flow Diagram Of Typical SCR Installation

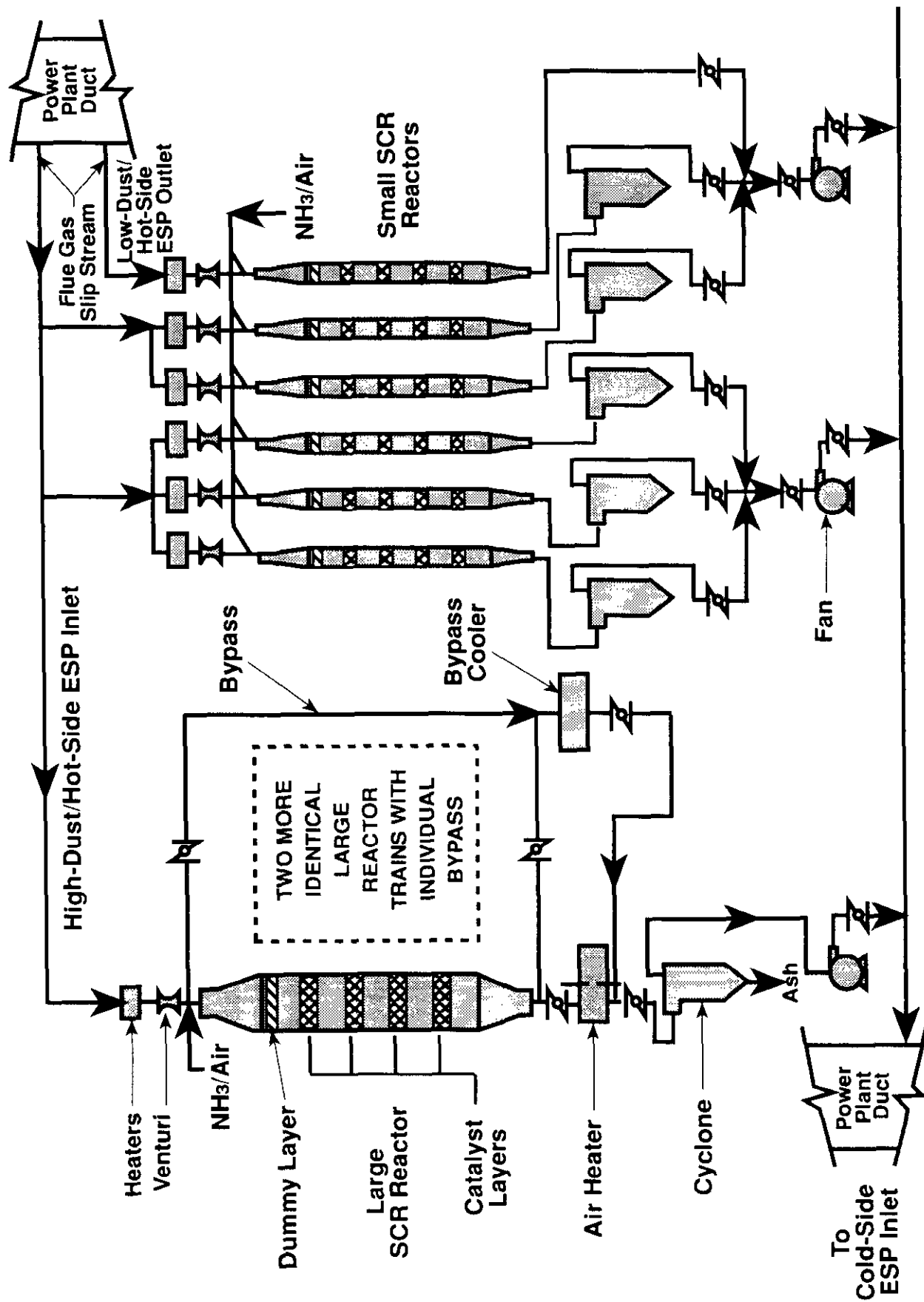


Figure 2. Prototype SCR Demonstration Facility-Process Flow Diagram.

Table 1: SCR Project Catalyst Suppliers

<u>Catalyst Vendor</u>	<u>Reactor Size</u>	<u>Catalyst Configuration</u>
Nippon Shokubai	Large	Honeycomb
Siemens AG	Large	Plate
W. R. Grace	Large	Honeycomb
W. R. Grace	Small	Honeycomb
Haldor Topsoe	Small	Plate
Hitachi Zosen	Small	Plate
Cormetech	Small	Honeycomb
Cormetech	Small	Honeycomb (low dust)

Table 2: Project Schedule

Detailed Engineering	1/92 - 12/92
Construction	3/92 - 2/93
Start-up/Shakedown	1/93 - 6/93
Process Evaluation	7/93 - 6/95
Disposition/Final Report	7/95 - 10/95

Table 3: Test Facility Inlet Flue Gas Composition

<u>Constituent</u>	<u>ESP Inlet</u>		<u>ESP Outlet</u>	
	<u>84 MW</u>	<u>43 MW</u>	<u>84 MW</u>	<u>43 MW</u>
NO _x	325	401	332	Not Available
SO ₂ (ppm)	2340	1780	2030	1510
SO ₃ (ppm)	32	42	14	20
HCl (ppm)	104	89	115	101
NH ₃ (ppm)	<0.4	<0.4	<0.4	<0.4
Particulate (gr/dscf)	3.76	2.43	0.0018	BDL*

* Below detection limits

Table 4: Particulate Loading to Reactors

Reactor	Ash Loading (84 MW) (gr/dscf)	Ash Loading (43 MW) (gr/dscf)
A	3.65	3.08
B	4.18	3.04
C	3.96	3.16
D	2.83	2.70
E	3.96	3.22
F	4.01	3.04
G	3.60	2.71
H	3.52	2.75

Table 5: SO₂ Oxidation Across Test Facility Without Catalyst
SO₃ (ppm)

		<u>Heater Inlet</u>	<u>Heater Exit</u>	<u>Reactor Exit</u>
Large Reactor	84 MW	12	15	10
	43 MW	31	40	32
Small Reactor	84 MW	8	11	7
	43 MW	28	35	23

Table 6: Test Facility Average Inlet Gas Concentrations
July-December, 1993

<u>Constituent</u>	<u>Average</u>	<u>High</u>	<u>Low</u>
Unit #5 Load (MW)	66	83	44
Inlet NO _x (ppm)	318	369	274
Inlet O ₂ (%)	4.8	7.1	2.6
Inlet CO ₂ (%)	13.2	16.8	10.6
Inlet CO (ppm)	36	248	5
Inlet SO ₂ (ppm)	1670	1930	1420

Table 7: Average Air Preheater Operational Parameters

July-December, 1993

<u>Parameter</u>	<u>APH A</u> <u>(2-Layer Rotary)</u>	<u>APH B</u> <u>(3-Layer Rotary)</u>	<u>APH C</u> <u>(Heat Pipe)</u>
Gas flow rate (SCFM)	4628	4709	5274
Air flow rate (SCFM)	4550	3830	5960
Inlet gas temp. (°F)	653	655	662
Exit gas temp. (°F)	319	309	311
Inlet air temp. (°F)	87	87	87
Exit air temp. (°F)	599	583	510
Gas side press. drop ("H ₂ O)	4.02	4.27	2.03
Air side press. drop ("H ₂ O)	1.77	1.63	NA
Air/Gas diff. press. ("H ₂ O)	0.53	0.45	NA
Inlet gas O ₂ (% wet)	5.08	5.14	4.97
Exit gas O ₂ (% wet)	6.98	8.23	NA

Table 8: Baseline SO₂ Oxidation Performance

Cat.#	Flow Rate	Temp.	NO _x IN	NH ₃ /NO _x	NO _x Red.	SO ₂ Ox.
	<u>(SCFM)</u>	<u>(F)</u>	<u>(ppmv)</u>	<u>Ratio</u>	<u>(%)</u>	<u>(%)</u>
1	4191	700	279	0.93	91%	0.0
2	4313	700	267	1.17	97%	1.2
3	4372	700	239	0.92	89%	0.2
4	373	700	324	0.86	84%	0.0
5	373	700	294	0.95	93%	0.4
6	373	700	295	0.95	93%	0.8

Table 9: Baseline NH₃ Slip Performance

Cat.#	Flow Rate	Temp.	NO _x In	NH ₃ /NO _x	NO _x Red.	NH ₃ Slip
	<u>(SCFM)</u>	<u>(F)</u>	<u>(ppmv)</u>	<u>Ratio</u>	<u>(%)</u>	<u>(ppmv)</u>
1	4208	700	307	0.99	96%	0.9
2	4221	700	298	0.96	96%	4.0
3	4491	700	286	0.92	89%	5.7
4	377	700	305	0.87	86%	0.7
5	373	700	305	0.94	92%	< 0.8
6	372	700	300	0.95	93%	2.4

The following technical paper was unavailable at time of publication:

TVA MICRONIZED COAL REBURN PROJECT UPDATE

C. Howlett
Fuller Company

Please contact author for a copy of this paper.

TECHNICAL SESSION 4:
NO_x CONTROL TECHNOLOGIES

Co-Chairs:

Arthur L. Baldwin
Pittsburgh Energy Technology Center
U.S. Department of Energy

William E. Fernald
Office of Clean Coal Technology
U.S. Department of Energy

**ROSEBUD SYNCOAL PARTNERSHIP
SYNCOAL® DEMONSTRATION
Technology Development Update**

**Ray.W. Sheldon, P.E.
Rosebud SynCoal Company
Billings, MT**

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Pittsburgh Energy Technology Center
Pittsburgh, PA**

**Presented at:
Third Annual Clean Coal Technology Conference
September 6-8, 1994
Chicago, Illinois**

ROSEBUD SYNCOAL PARTNERSHIP
SYNCOAL® DEMONSTRATION
Technology Development Update

INTRODUCTION

Rosebud SynCoal® Partnership's Advanced Coal Conversion Process (ACCP) is an advanced thermal coal upgrading process coupled with physical cleaning techniques to upgrade high-moisture, low-rank coals to produce a high-quality, low-sulfur fuel.

The coal is processed through two vibrating fluidized bed reactors where oxygen functional groups are destroyed removing chemically bound water, carboxyl and carbonyl groups, and volatile sulfur compounds. After thermal upgrading, the SynCoal® is cleaned using a deep-bed stratifier process to effectively separate the pyrite rich ash.

The SynCoal® process enhances low-rank western coals with moisture contents ranging from 25-55%, sulfur contents between 0.5 and 1.5%, and heating values between 5,500 and 9,000 Btu/lb. The upgraded stable coal product has moisture contents as low as 1%, sulfur contents as low as 0.3%, and heating values up to 12,000 Btu/lb.

Construction of the 300,000 ton per year (tpy) demonstration project adjacent to Western Energy Company's Rosebud mine unit train loadout facility near the town of Colstrip in southeastern Montana was completed in 1992. An extended startup and shakedown period lasted until August 1993. The facility has produced nearly at-design capacity since January 1994. Rosebud SynCoal's demonstration plant is sized at about one-tenth the projected throughput of a multiple processing train commercial facility. The next generation of facilities are expected to become standardized 100 TPH process trains.

Demonstration operations and testing began in April 1992 and are continuing. Initial operations discovered the normal variety of equipment problems which delayed operational and process testing. As operational testing has proceeded, the product quality issues that have emerged are dustiness and stability. The SynCoal® product has met the BTU, moisture and sulfur specifications. The project team is continuing process testing and is working toward resolution of the operational and process issues in response to market requirements.

The ACCP Demonstration Facility is a U.S. Department of Energy (DOE) Clean Coal Technology Program Project with 50% funding from the DOE and 50% from the Rosebud SynCoal Partnership through the end of the original \$69 million project. DOE and Rosebud recently agreed to extend the project until November 1997 with total funding increasing to \$105.7 million and DOE's contribution increased to a total of \$43.125 million.

The Rosebud SynCoal Partnership is a venture involving Western SynCoal Company and Scoria Inc.. Western SynCoal is a subsidiary of Western Energy Company (WEC) which is a subsidiary of Entech Inc., Montana Power Company's non-utility group. Scoria Inc is a subsidiary of NRG Energy Inc., Northern States Power's non-utility group.

STATUS OF DEVELOPMENT

Much of the early ACCP development was performed using a small, 150 pound per hour pilot plant located at the Mineral Research Center, south of Butte, Montana. Up to 100 ton lots were produced to assess shipping and handling stability as well as chemical characteristics. A variety of coals and process conditions were tested to determine the process capabilities.

Development is continuing as construction and startup has been completed and demonstration operation is continuing at the 300,000 ton per year demonstration plant at Western Energy's Rosebud Mine near Colstrip, Montana. The demonstration facility has operated nearly at full design capacity during 1994, reaching as much as 115 percent of design on an hourly basis for short periods of time. Rosebud SynCoal is developing facility designs and equipment concepts around 100 TPH process units that can be added in multiples to make facilities at virtually any

production capacity desired. A listing of the most significant events in the history of the ACCP development is provided in Appendix A.

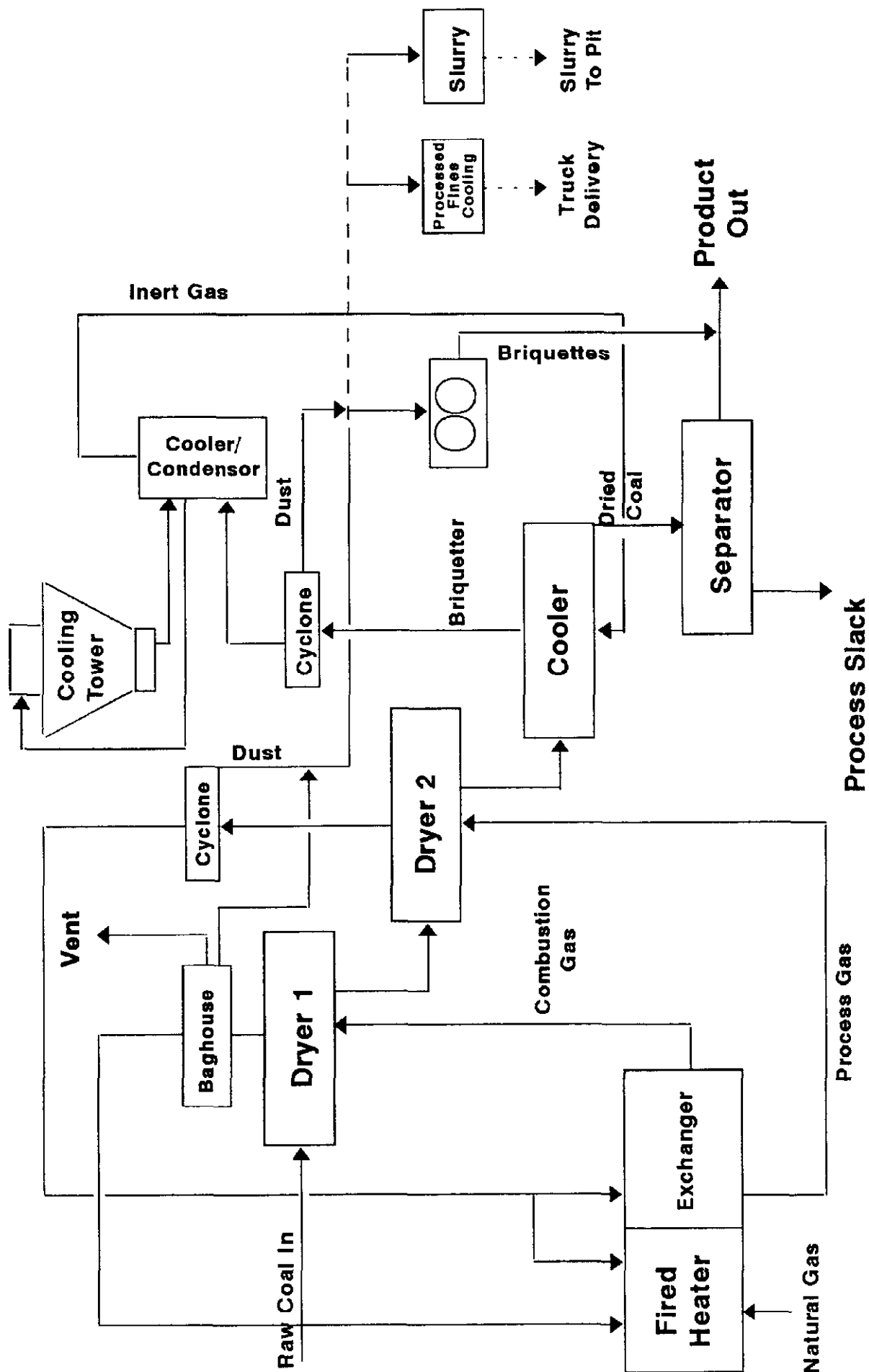
PROCESS DESIGN DESCRIPTION

In general, the ACCP is a low rank coal upgrading and conversion process using low pressure, superheated gases to process coal in vibrating fluidized beds. Two vibratory fluidized processing stages are used to heat and convert the coal followed by a water spray quench and a vibratory fluidized stage to cool the coal. The solid impurities are then removed from the dried coal using pneumatic separators. Other systems servicing and assisting the coal conversion system are:

- ▶ Product Handling
- ▶ Raw Coal Handling
- ▶ Emission Control
- ▶ Heat Plant
- ▶ Heat Rejection
- ▶ Utility and Ancillary

The nominal throughput of the demonstration plant is 450,000 tpy (1,640 tpd) of raw coal, providing 242,000 tpy (886 tpd) of coarse SynCoal® product and 66,000 tpy (240 tpd) of SynCoal® fines (minus 20 mesh). The fines are to be collected and sold, giving a combined product rate of 308,000 tpy (1,126 tpd) of high-quality, clean SynCoal® product. The central processes are depicted in Figure 1, the Process Flow Schematic.

Process Flow Diagram



Flowdgm

Coal Conversion

The coal conversion is performed in two parallel processing trains. Each consists of two 5-foot wide by 30-foot long vibratory fluidized bed/reactors in series, followed by a water spray quench section and a 5-foot wide by 25-foot long vibratory cooler. Each processing train is fed 1,139 pounds per minute of sized coal.

In the first-stage dryer/reactors, the coal is heated using recirculated combustion gases, removing primarily surface water from the coal. The coal exits the first-stage dryer/reactors, at a temperature slightly above that required to evaporate water, and is gravity fed into the second-stage reactors. Here the coal is heated further using a superheated gas stream, removing water trapped in the pore structure of the coal, and promoting the thermal destruction of the oxygen functional groups, such as hydroxyls, carbonyls and carboxylate that are normally prevalent in lower rank coals. The superheated gases used in the second stage are actually produced from the coal. The make-gas from the second stage system is used as an additional fuel source in the process furnace, incinerating all the hydrocarbon gases produced in the process. The particle shrinkage that liberates ash minerals and imparts a unique cleaning characteristic to the SynCoal® also occurs in the second stage. As the coal exits the second-stage reactors, it falls through vertical quench coolers where process water is sprayed onto the coal to reduce the temperature. The water vaporized during this operation is drawn back into the second-stage exhaust gas. After quenching, the SynCoal® enters the vibratory coolers where the SynCoal® is contacted by cool inert gas. The SynCoal® exits the cooler at less than 150 degrees Fahrenheit (F) and is conveyed to the pneumatic cleaning system. The cooler exit gas is cooled by direct contact with water prior to returning to the vibratory fluidized coolers.

Coal Cleaning

The SynCoal® entering the cleaning system is screened into four size fractions: plus 1/2 inch, 1/2 by 1/4 inch, 1/4 inch by 6 mesh, and minus 6 mesh. These streams are fed in parallel to four deep-bed stratifiers (stoners), where a rough specific gravity separation is made using fluidizing air and a vibratory conveying action. The light (lower specific gravity) streams from the stoners are sent to the product conveyor; the heavy streams from all but the minus 6 mesh stream are

sent to gravity separators. The heavy fraction of the minus 6 mesh stream goes directly to the waste conveyor. The gravity separators, again using air and vibration to effect a separation, each split the coal into light and heavy fractions. The light stream is considered product; the heavy or waste stream is sent to a 300 ton storage bin to await transport to an off site user or alternately back to a mined out pit disposal site. The dry, cool, and clean product from coal cleaning enters the product handling system.

Product Handling

Product handling conveys the clean product coal to two 6,000 ton capacity concrete silos and allows unit train loading with the mine's tippie loadout system. SynCoal® fines are collected from the process baghouses and cyclones using screw and chain conveyors. The SynCoal® fines are conveyed to an indirect cooler that uses water cooled plates to reduce the temperature of this product to safe levels. The fines are then conveyed to a 250 ton truck loadout for sale.

Raw Coal Handling

Raw sub-bituminous coal from the existing Rosebud Mine A/B stockpile is screened to provide 1-3/4 x 3/8 inch feed for the ACCP process. Coal rejected by the screening operation is conveyed back to the active stockpile. Properly sized coal is conveyed to a 1,000 ton raw coal storage bin which feeds the process facility.

Emission Control

The fugitive dust from the coal cleaning system is controlled by placing hoods over the generation sources and conveying the dust laden air to fabric filter(s). The bag filters can remove 99.99 percent of the coal dust from the air before discharge. All fines report to a fines handling system than can briquette or cool the fines for product sales or make a slurry for disposal.

Sulfur dioxide emission control philosophy was based on injecting dry sorbent (sodium bicarbonate) into the ductwork to minimize the release of sulfur dioxide to the atmosphere.

Testing has shown very low SO₂ emissions occur inherently from the process, less than one-fifth the level expected with the emission control; therefore, the dry sorbent injection is not being used.

Heat Plant

The heat required to process the coal is provided by a natural gas fired process furnace. This system is sized to provide a heat release rate of 58 MM BTU/hr. Process gas enters the furnace and is heated by radiation and convection from the burning fuel. Process make gas from coal conversion is used as fuel in the furnace. A commercial scale plant would most likely use a coal fired process furnace due to the much lower energy cost of coal.

Heat Rejection

Heat rejection from the ACCP is accomplished mainly by releasing water and flue gas to the atmosphere through the exhaust stack. The stack design allows for vapor release at an elevation great enough that, when coupled with the vertical velocity resulting from a forced draft fan, maximize the dissipation of the gases. Heat removed from the coal in the coolers is rejected using an atmospheric induced-draft cooling tower.

Utility and Ancillary Systems

The coal fines that are collected in the conversion, cleaning and material handling systems are gathered and conveyed to a surge bin. The coal fines are then briquetted and returned to the product stream.

The common facilities include a plant and instrument air system, a fire protection system, and a fuel gas supply and distribution system.

The power distribution system includes a 15 KV service, a 15 KV/5 KV transformer, a 5 KV motor control center, two 5 KV/480 V transformers, two 480 V load distribution centers, and six 480 V motor control centers. An uninterruptible power supply (UPS) was added to provide minimal power for control and emergency functions in the event of power interruptions.

Control of the process is fully automated including dual control stations, dual programmable logic controllers, distributed plant control, and data acquisition hardware.

PRODUCT CHEMISTRY

Rosebud SynCoal's Advanced Coal Conversion Process yields a synthetic solid fuel that represents an evolutionary step in the coalification process. Western U.S. lignite and sub-bituminous coals are converted by the thermal environment of the ACCP to a higher rank fuel.

The ACCP changes the chemical composition and structure of the coal feedstock. The changes include:

- ▶ Increased higher heating value;
- ▶ Increased aromaticity;
- ▶ Increase fixed carbon;
- ▶ Increased carbon to hydrogen ratios;
- ▶ Increased carbon + hydrogen to oxygen ratios;
- ▶ Decreased moisture content;
- ▶ Decreased sulfur content per million Btus;
- ▶ Decreased ash content per million Btus; and
- ▶ Decreased oxygen functional groups.

The above changes are the result of the thermo-chemical reactions induced by the ACCP and the enhanced ability to remove the pyritic and ash forming minerals resulting in the upgraded synthetic coal product.

The demonstration project has allowed the SynCoal organization to test North Dakota lignite and Wyoming sub-bituminous coals as well as the regular Rosebud sub-bituminous feedstock.

The average analyses of the coal feedstocks and upgraded products from the demonstration plant are shown in Table 1. The first section of the table shows standard proximate and ultimate coal

TABLE 1 - SYNCOAL QUALITY COMPARISONS - RAW FEEDSTOCKS VS. PRODUCTS

	ROSEBUD SYNCOAL			CENTER SYNCOAL			POWDER RIVER SYNCOAL		
	FEEDSTOCK AND COAL PRODUCT ANALYSIS			FEEDSTOCK AND COAL PRODUCT ANALYSIS			FEEDSTOCK AND COAL PRODUCT ANALYSIS		
	Raw Coal Feedstock	Rosebud SynCoal	Rosebud Fines	Raw Coal Feedstock	Center SynCoal	Center Fines	Raw Coal Feedstock	Powder River SynCoal	Powder River Fines
Proximate Analysis									
% Moisture	25.24	2.21	5.59	36.17	7.35	10.26	28.11	4.51	6.22
% Volatile Matter	29.16	36.98	35.32	27.13	39.39	36.33	31.78	41.4	39
% Fixed Carbon	36.69	51.19	49.65	30.16	46.74	43.92	35.25	47.48	48.48
% Ash	8.92	9.2	9.44	6.54	6.52	9.49	4.86	6.61	6.3
% Sulfur	0.74	0.56	0.87	1.07	0.77	1.06	0.34	0.45	0.48
BTU/lb	8634	11785	11194	7064	10799	9914	8727	11805	11339
lb SO ₂ /MMBTU	1.71	0.95	1.55	3.03	1.43	2.14	0.78	0.76	0.85
lb Ash/MMBTU	10.3	7.8	8.4	9.3	6.0	9.6	5.6	5.6	5.6
% Equilibrium Moisture	24.9	14.7	20.2	34.98	20.12	21.92	28.38	14.04	20.2
Ultimate Analysis									
% Carbon	50.54	68.16	64.8	42.25	64.15	59.17	49.7	66.96	64.89
% Hydrogen	3.33	4.7	4.37	2.62	4.11	3.74	3.69	4.93	4.56
% Oxygen	10.47	13.52	13.83	10.76	16.22	15.35	12.52	15.39	16.48
% Nitrogen	0.76	1.23	1.1	0.59	0.88	0.93	0.78	1.15	1.07
C:H Ratio	15.18	14.50	14.83	16.13	15.61	15.82	13.47	13.58	14.23
{C+H}:O Ratio	5.15	5.39	5.00	4.17	4.21	4.10	4.26	4.67	4.21
Petrographic Analysis									
% Huminite by volume	68.1	69.4	68.7	73.4	85.1	74.5	73.4	85.1	74.5
% Liptinite by volume	7.8	6	4.4	4.2	4.4	5.2	4.2	4.4	5.2
% Inertinite by volume	16.2	18.9	21.1	16.2	6.4	14.1	16.2	6.4	14.1
% Mineral Mater by volume	7.9	5.6	5.8	6.2	4.1	6.2	6.2	4.1	6.2
Reflectance	0.38	0.45	0.44	0.33	0.36	0.36	0.35	0.38	0.40
Carboxyl Concentration Analysis									
% COOH	0.85	0.26	0.46	0.53	0.17	0.31	1.02	0.15	0.41
Classification ASTM	Subbituminous C	High vol C bituminous	High vol C bituminous	Lignite A	High vol C bituminous	Subbit A	Subbit C	High vol C bituminous	High vol C bituminous

* MAF - Moisture and Ash Free

analyses of the coal feedstock and the synthetic coal product. The second section of the table shows additional analyses showing the coal upgrading by the process.

Moisture is essentially eliminated from the coal during the ACCP. This moisture removal is due to thermal dehydration of the coal particle both physical and chemical, and the chemical condensation reactions which the feedstock experiences during its residence in the high temperature environment of the second-stage reactor bed.

The moisture-free analysis of the feedstock and the upgraded product also show that, to a large extent, both the volatile matter and the fixed carbon content is retained in the SynCoal product. This phenomenon is significant and desirable, because normally raw coal, when subjected to the temperatures of the ACCP, would undergo devolatilization and substantial gasification. The ACCP products are much more desirable fuels because of their extremely good ignitability and complete combustion causing many observers to comment that it "burns like natural gas" except the opaque flame provides more radiant heat providing an additional benefit to direct fired kiln operations.

The reduction in total sulfur is due primarily to the mechanical removal of pyrites during the cleaning step. However, the ability to remove these pyrites is a result of the chemical repolymerization and consequent shrinkage of the organic components of the coal, which causes fracture release of the ash or mineral components. A small amount of organic sulfur is volatilized from the coal in the form of hydrogen sulfide (H_2S) during the upgrading process.

PROJECT STATUS

Construction of Rosebud SynCoal's ACCP Demonstration Facility was completed during the first quarter of 1992 at a total cost of approximately \$35 million. Initial equipment startup was conducted from December 1991 through March 1992. Initial operations discovered the normal variety of equipment problems. The project's startup and operations groups worked together to overcome the initial equipment problems and achieve an operating system. The fines handling equipment was undersized originally and required a significant modification to expand the capability of this system. This modification was completed in August 1993. The lack of fines handling capacity prevented the facility from achieving full production rate and limited operating hours due to frequent fines handling equipment failures. The new fines handling system has expected to allow full production and more reliable operations. Table 2 shows the improved operations since September 1993.

TABLE 2 - SYNCOAL DEMONSTRATION OPERATING STATISTICS

Month	Production Availability	Forced Outage Rate	Tons Processed	Capacity Factor	Shipments
Sept 1993	73%	18%	14,371	65%	3,545
Oct 1993	76%	11%	23,528	63%	12,753
Nov 1993	85%	14%	27,930	74%	14,349
Dec 1993	74%	9%	26,009	69%	16,951
Jan 1994	73%	17%	34,979	93%	18,754
Feb 1994	67%	25%	29,280	85%	7,369
March 1994	82%	13%	41,891	112%	24,351
April 1994	72%	26%	34,438	92%	15,022
May 1994	76%	17%	39,440	105%	26,355
June 1994	77%	23%	36,657	98%	18,772

The SynCoal® product has displayed a tendency towards self heating that was not expected. The project's technical and operating team has conducted an extensive process testing program in

order to determine the cause of the product's lack of stability. A number of approaches have been partially successful; however, to date, the demonstration product has not met the level of resistance to spontaneous combustion that was apparent in the earlier pilot plant work. This has reduced the storage life and as a result delayed the full-scale test burn program. An initial test burn program has been conducted at Montana Power's Corette station. A significant amount of handling and storage testing was conducted in preparation for the anticipated full-scale test burn program.

A test program was initiated March 1, 1994 at the J.E. Corette power plant using a 50/50 blend of raw sub-bituminous and DSE Conditioned SynCoal®. Testing has continued into the summer with some variations in plant loads and blend ratios. The results are still being evaluated, but the immediate indications include significantly improved boiler cleanliness, efficiency and operations capacity while the SO₂ emissions decreased with no noticeable effect on NO_x. With the higher SynCoal® blends SO₂ emissions decrease by as much as 43% and the plant could hold a 170 MWe load which is well above the normal 160 MWe load. The boiler efficiency increased from 84.9% to 85.7% with the 50/50 blend and to 86.2% with a 75/25 blend. The corresponding decreases in net unit heat rate were 130 Btu/kWh and 181 Btu/kWh respectively.

Additional testburning is anticipated later this year in a variety of facilities. The primary marketing focus this year has been expanding the industrial market applications of SynCoal®. This market niche is the most lucrative for SynCoal since it can take better advantage of the specific benefits of SynCoal®, adapts quickly and will pay for the additional benefits.

PROJECTIONS FOR THE FUTURE

The Rosebud Syncoal Partnership intends to commercialize the process by both preparing coal in their own plants and by licensing to other firms. The target markets are primarily the U.S. utilities, the industrial sector and Pacific Rim export market. Current projections suggest the utility market for this quality coal is approximately 60 million tons per year with potential industrial markets of 38 million tons per year. The Partnership is currently working on three

potential semi commercial projects tentatively located in Wyoming, North Dakota and Montana. Each project represents significant enhancements toward the ultimate goal of a standardized process train and modular commercial design that will allow development of future facilities sized to match the needs of the specific markets anywhere from 500,000 to 5 million tons per year.

The Wyoming project is a stand alone mine mouth design. The North Dakota project is integrated into a mine mount power plant with the product sales offsite to regional markets. The Montana project is designed either as an integration into a power plant and fuel user or an expansion of the existing demonstration facility.

CONCLUSION

The ACCP is a relatively simple, low pressure, medium temperature coal upgrading and conversion process. The synthetic upgraded coal product exhibits the characteristics of reduced equilibrium moisture level, reduced sulfur content and increased heating value. The SynCoal product retains a majority of its volatile matter and demonstrates favorable combustion characteristics.

Although some difficulties have been encountered, SynCoal's technical and operating team are resolving the issues and SynCoal marketing is starting to expand rapidly. The ACCP Demonstration program is continuing with a complete team effort involving all three of the major participants. It is expected that the ACCP demonstration will continue to produce test results and technology development through the extended demonstration resulting from DOE's expanded funding and time schedule and the continued efforts of the Rosebud SynCoal Partnership.

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SynCoal® is a registered trademark of the Rosebud SynCoal Partnership.

APPENDIX A

ADVANCED COAL CONVERSION PROCESS SIGNIFICANT EVENTS

September	1981	Western Energy contracts Mountain States Energy to review LRC upgrading concept called the Greene process.
November	1984	Initial operation of a 150 lb/hr continuous pilot plant modeling the Greene drying process at Montana Tech's Mineral Research Center in Butte, Montana.
December	1984	Initial patent application filed for the Greene process, December 1984.
January	1986	Initiated process engineering for a demonstration-size Advanced Coal Conversion Process (ACCP) facility.
October	1986	Completed six month continuous operating test at the pilot plant with over 3,000 operating hours producing approximately 200 tons of SynCoal®.
October	1986	Western Energy submitted a Clean Coal I proposal to DOE for the ACCP Demonstration Project in Colstrip, Montana, October 18, 1986.
November	1987	Internal Revenue Service issued a private letter ruling designating the ACCP product as a "qualified fuel" under Section 29 of the IRS code, November 6, 1987.
February	1988	First U.S. patent issued February 16, 1988, No. 4, 725,337.
May	1988	Western Energy submitted an updated proposal to DOE in response to the Clean Coal II solicitation, May 23, 1988.
December	1988	Western Energy was selected by DOE to negotiate a Cooperative Agreement under the Clean Coal I program.
March	1989	Second U.S. patent issued March 7, 1989, No. 4, 810,258.
September	1990	Signed Cooperative Agreement, after Congressional approval, September 13, 1990.
September	1990	Contracted project engineering with Stone & Webster Engineering Corporation, September 17, 1990.
December	1990	Formed Rosebud SynCoal Partnership, December 5, 1990.

December	1990	Started construction on the Colstrip site.
March	1991	Novated the Cooperative Agreement to the Rosebud SynCoal Partnership, March 25, 1991.
March	1991	Formal ground breaking ceremony in Colstrip, Montana, March 28, 1991.
December	1991	Initiated commissioning of the ACCP Demonstration Facility.
April	1992	Completed construction of the ACCP Demonstration Facility and entered Phase III, Demonstration Operation.
June	1992	Formal dedication ceremony for the ACCP Demonstration Project in Colstrip, Montana, June 25, 1992
July	1992	Identified a variety of mechanical and process issues.
June	1993	Initiated deliveries of SynCoal® under a contract with industrial customer.
August	1993	State evaluated emissions, and the ACCP process is in compliance with air quality permit. ACCP Demonstration Facility went commercial on August 10, 1993, having resolved major mechanical issues.
October	1993	Tested North Dakota lignite as a potential process feedstock, achieving nearly 11,000 Btu/lb heating value and substantially reducing the sulfur content in the resultant product.
December	1993	Signed a Letter of Intent with Minnkota Power Cooperative to attempt development of a SynCoal® facility at M.R. Young plant site near Center, ND.
May	1994	Tested Wyoming Powder River sub-bituminous coal as a potential process feedstock, achieving 11,800 Btu/lb heating value in the resultant product.

CONTINUOUS OPERATION AND COMMERCIALIZATION OF THE ENCOAL MILD COAL GASIFICATION PROJECT

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ABSTRACT

ENCOAL Corporation, a wholly owned subsidiary of SMC Mining Company, which is a subsidiary of Zeigler Coal Holding Company, has recently achieved continuous operation in a production mode with its Liquids From Coal (LFC) plant at Triton Coal Company's Buckskin Mine near Gillette, Wyoming. Operating at 50% of design capacity, the plant has now set a record of 68 straight days at 90% availability. More than 12,000 tons of stable Process Derived Fuel (PDF), an upgraded coal product similar to a bituminous coal with very low sulfur, were produced in the run. In addition, 600,000 gallons of Coal Derived Liquid (CDL) were also produced. CDL is a very low sulfur industrial fuel.

While logging more than 2,600 hours of operation this year, the plant has processed 35,000 tons of Powder River Basin subbituminous coal. All of the major equipment has now been demonstrated to be reliable and most of the plant testing phase is complete. CDL is routinely being shipped to industrial customers. The first shipment of PDF to industrial and utility

customers is expected shortly. Although not performing completely up to expectations, a new product finishing step added last year is now in operation and ENCOAL has learned how to consistently deactivate the PDF product.

Marketing activities for the products and the LFC technology have increased with the successful operation of the Gillette plant. Domestic and international potential customers for the technology have been identified and many contacts have been made. Laboratory testing of candidate coals is available and computerized methods are used to predict product recoveries and economics for the specific projects. SGI International, the original developer of the LFC Technology and licensing partner, has produced numerous reports on these commercial prospects as discussed further in the paper.

This paper summarizes the operations and marketing activities to date. Data is presented on the plant operating statistics and product qualities. Also presented are the results of shipping and handling tests performed at the ENCOAL plant. A brief discussion of background information including the plant and process design is presented. Also included is a generic discussion of the modifications made to the LFC plant to get it to the production mode. The Project Team's activities in the commercialization of the technology are also discussed.

The CQE Project: Producing Innovative Software for Economical Deployment of Coal Technologies

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Black & Veatch

ABSTRACT

This paper describes the CQE, a development of the US DOE Clean Coal Technology solicitation. The CQE is a software tool to provide a means for analyzing increasingly complex fuels procurement and management issues. These include direct effects, such as sourcing, transportation, unit maintenance and availability, fuel price and quality, emissions, and operations impacts, as well as indirect issues such as generation planning or plant retrofits. CQE is fuel independent, building on industry's existing base of coal technology, but also capable of providing analysis of non-coal fuel issues, such as gas co-firing. CQE relies on three elements to bolster its future success: flexibility, advanced technical models, and an advanced user interface.

THE GROWING NEED

Growing competition among power producers, increasingly stringent emissions regulations, and advances in power generation technology are changing the business of power generation worldwide. Such pressures will impact the many varied and important fuel purchase decisions which account for between 30 and 70 percent of a utility's annual expenditures. This fraction is likely to rise, as the cost of emission allowances or other environmental considerations enter the cost mix. Unfortunately, understanding coal quality and its impacts on plant performance, emissions, and production costs is difficult proposition.

Coal quality impacts nearly every system present at the power plant. Measuring or quantifying such impacts requires a comprehensive and complex analysis of the power plant's performance. The very complexity of coal, its combustion, and the resulting relationships to performance, emissions, and costs continues to be a major driving force behind many coal quality effects R&D programs active throughout the world and many computer products, current and future.

The diversity of fuel decisions further complicates the situation. Coal quality

concerns (Table 1) span many areas of the utility organization with each area having specific, yet very different, needs.

- **Fuel Supply and Procurement.** Rapid evaluation of alternative suppliers and fuel specifications, with emphasis on finding least-cost, acceptable sources.
- **Engineering.** Detailed analysis of coal quality/performance relationships and analysis of potential plant retrofit projects.
- **Production.** Understanding of how adjustments to operating practices influences impacts of coal quality.
- **Environmental.** Relationship between fuel sources to emissions, both short- and long-term.
- **System Planning.** Influence of fuel sourcing on system-wide production cost, unit dispatch, and annual emission rates.
- **Management.** Influence of fuel sourcing options on production costs and flexibility of utility to adapt to changing market influences.

TABLE 1

Heating Value	The heating value will directly affect the required fuel burn rate and therefore directly impact the design and performance of most of the systems within a power plant. Lower heating value will result in higher design flows for coal handling, fuel preparation, combustion air, ash handling, and waste systems. Since most coals are purchased on a heating value basis, this parameter is directly linked to a utility's production costs.
Moisture Content	The moisture content affects boiler efficiency (and thus fuel burn rate), combustion zone flame temperature, convective heat transfer, and air preheat requirements.
Ash Content	Ash content directly affects design capacities of ash handling systems, particulate removal, and waste disposal land needs. Characteristics of the ash also have significant impact on system design including ash erosion considerations, and steam generator design impacts to avoid slagging and fouling. Information on ash disposal costs and environmental considerations are of interest to non-fuel utility personnel. Maintenance and operating costs also vary with ash content.
Ultimate Analysis	The ultimate analysis determines combustion air and flue gas flows. Design impacts include fan sizes and power requirements, air heater size, and ductwork and emission limit system sizing. The major effects of the constituents of the ultimate analysis are presented below.

Sulfur Content	Besides design impacts on the SO ₂ removal system, sulfur content can affect the cold-end corrosion of regenerative air heaters and thus controls the air heater outlet temperature and affects boiler efficiency. Corporate environmental plans are directly affected by this coal parameter.
Chlorine Content	Chlorine affects the fouling potential of coal ash.
Nitrogen Content	The boiler design must consider nitrogen content to ensure NO _x limits are not exceeded.
Volatile Matter	The volatile matter affects the fineness to which coal must be pulverized to provide acceptable combustion characteristics and thus affects pulverizer design and operation.
Ash Composition	Ash composition effects the propensity of coal to slag or foul steam generator heat transfer surface, the reflectivity of ash deposits, the abrasiveness of ash/flue gas passing through various system, and the collection efficiency of electrostatic precipitators. Hence, ash composition effects the size and surface arrangement of a boiler, the size of the electrostatic precipitator, boiler and ash handling material selection, and ductwork arrangement/sizing. Availability, capacity, and generation are system consequences of these impacts.

Utilities need a consistent, timely means of evaluating coal quality impacts as well as a means for integrating such information into its day-to-day decision processes.

THE VISION, THE CHALLENGE, AND THE STRATEGY

Ongoing and past research efforts at the Department of Energy (DOE), the Electric Power Research Institute (EPRI), other international research organizations, and equipment manufacturers have focused on the many difficult coal quality issues.

CQE, under development as part of a \$23 million U.S. Clean Coal Technology project sponsored by the Department of Energy and EPRI, will offer unparalleled advancements in technical capability, flexibility, and integration. Currently under development and scheduled for initial release in June 1995, CQE will bring a new level of sophistication to fuel decisions by seamlessly integrating the system-wide effects of fuel purchase decisions on power plant performance, emissions, and power generation costs. CQE will feature both integration of already proven and extensively used computer programs such as the EPRI Coal Quality Impact Model (CQIM™) and new relationships derived from the project's comprehensive full-, pilot-, and bench-scale testing programs.

CQE will be composed of technical models to evaluate performance issues; environmental models to evaluate environmental and regulatory issues; and cost estimating models to predict costs for installations of new and retrofit coal cleaning processes, power production equipment, and emissions control systems as well as

other production costs such as consumables (fuel, scrubber additive, etc.), waste disposal, operating and maintenance, and replacement energy costs. The foundation for CQE's calculation power begins with CQIM.

Since its introduction in 1989, the CQIM has demonstrated wide application in a number of fuel purchase assessment areas. It has been used by over 70 utilities, engineering firms, and coal companies in the United States, as well as a growing number of international users for a variety of applications, including:

- Fuel procurement decisions and negotiations
- Clean Air Compliance strategies, including fuel switching
- Coal contract specifications and value analysis
- Test burn planning and analysis
- Engineering analysis

CQE extends state-of-the-art in fuel assessment modeling in three dimensions, each discussed further in subsequent sections:

- New Flexibility and Application
- Advanced Technical Models and Performance Correlations
- Advanced User Interface and Network Awareness

The First Dimension: Flexibility and Application

CQE's architecture and program structure is designed to promote flexibility to the greatest extent practical.

- Flexibility to address the engineering and analytical needs of fuel purchasing specialists, engineers, operation support staff, and planners.
- Flexibility to perform its many "calculations" tailored to the needs of the specific audience and specific problem in question.

New flexibility is largely a function of two factors: use of object-oriented programming techniques, and CQE's innovative Application framework.

Object-Oriented Programming Techniques. CQE will be coded entirely in the C++ language, enabling the program to take advantage of the language's inherent strengths for managing large, complex analytical processes. Object-oriented programming also allows CQE to be fully extensible. An object-oriented CQE can simulate "real-world" objects, such as boilers, pulverizers, coals, and plants. By altering order, type, and content of queries between objects, different problems can be solved. Thus, the objects are "reused" to handle different situations. Unlike other methods, object-oriented techniques result in a design that interconnects data, objects and processing rather than processing alone. This provides flexibility by allowing users calculational access to any part of the program, in contrast to current software products, which restrict operation of the program to a pre-defined pathway.

The CQE has been designed such that future modifications can be easily made to enhance or replace current models. This objective will be accomplished by judicious application of object-oriented programming and maintaining an eye toward current or future related R&D efforts. The object-oriented approach is ideally suited to handling such future modifications; once the interface between objects has been determined, the internal contents of each object can be changed without altering the rest of the system. Thus, future advancements in coal quality analysis or models can be rapidly assimilated as follows:

- As technologies advance, existing models can be refined without disrupting or overhauling the entire system. Furthermore, new models--such as for selective catalytic reduction (SCR) or for a fluidized bed combustor--can be dropped into CQE to work seamlessly with existing ones.
- As the most commonly used equipment and system configurations are identified and built, users may share these pre-built systems, adding to their set of software models representing their individual systems. This will allow users to establish high quality models in a reduced time-frame, with lower resource expenditures.
- As new relationships between cost, emissions, and performance are proven, new CQE applications can be built.

It is this aspect of flexibility which will allow CQE to aid industry in making detailed, site-specific evaluations of candidate Clean Coal Technologies.

CQE Application Framework. An Application is the highest level of interface with the CQE system. Different Applications allow CQE to support a cross section of users with very specific, yet very different, needs. Fuels buyers, for instance, can use CQE to rank spot market fuel options, while environmental engineers can use CQE to evaluate different emissions compliance strategies. CQE streamlines analyses by matching software presentation to the specific task at hand. The major applications that will be available as a part of the CQE program include:

- **Coal Cleaning Expert.** Utilities or coal producers frequently consider altering quality of delivered coals via coal beneficiation. This process mainly consists of "cleaning" a raw coal to improve its coal quality and, as a result, increase unit efficiency and decrease unit emissions. The primary benefit in cleaning coal is a reduction in coal ash and sulfur content, with a commensurate increase in heating value. Coal cleaning can play a major role in reducing plant emissions and improving unit operation. Beneficiated coal can also reduce the total "fuel-related" generation costs, if the incremental cost of cleaning the coal is less than the savings realized at the station. CQE's Coal Cleaning Expert provides analysis capabilities for cost versus quality tradeoffs for a variety of cleaning processes and user specified coals.
- **Environmental Planner.** The Clean Air Act Amendments has put a premium

on viewing utility emissions from a "system" perspective. CQE's Environmental Planner is designed to rapidly calculate overall system costs, projected emissions, and allowance requirements as a function of potential technology options selected for individual units or stations within the system. The user can rapidly review alternative options (including fuel switching, fuel sorbent injection, installation of FGD systems, etc.) for each unit in question by selecting the potentially viable unit/technology marriages. This analysis can be easily extended to consider other facilities present in the system by simply entering appropriate cost, fuel, and operations data.

- **Fuel Evaluator.** A growing and more competitive power market, an evolving world coal market, more stringent emission regulations, and increased scrutiny by legislative/regulatory agencies, are some of the factors that have forced many electric utilities to change or alter their historic fuel procurement practices. Typically, this involves a re-evaluation of existing supplies and the establishment of relationships with new potential coal suppliers.

Depending upon the contributions from each cost component (fuel, transportation, unit efficiency, maintenance, availability, emissions control, waste disposal, equipment modifications, etc.), the competitive advantage of one fuel source relative to another may vary over the life of the power plant. Fuel switching (or blending) often represents an attractive alternative over other capital-intensive efforts for many units. Many utilities, particularly European and Eastern US utilities, have closely scrutinized changes in fuel sourcing at particular units because of the following:

- To reduce overall fuel expenditures, the unit may be evaluating lower quality coals to determine if savings which would result from lower fuel prices will be large enough to compensate for reductions in unit efficiencies and increases in operations and maintenance costs.
- To decrease maintenance costs and increase availability, the unit may be evaluating higher quality coals to determine if higher fuel prices can be justified by an increase in unit performance, a decrease in operations and maintenance costs, and possibly, the recovery of lost generation.
- To expand possible coal sources, the unit may want to consider spot-market coals. Perhaps in the past a long-term contract has bound the utility to a limited number of suppliers, and the expansion of fuel sources would thereby allow the utility to take advantage of the nature of the competitive fuel market.
- To comply with the legislative and political pressures for improving air quality including compliance with US Clean Air Act Amendments or European/local regulations (such as Helsinki and Sofia Protocols), the unit may be evaluating low-sulfur coals or blends as an alternative or, in addition to, other emission SO₂ reduction measures.
- To address regional socioeconomic concerns, a utility may elect to evaluate coals within a certain geographical proximity. The units' capability to

- burn these coals may have never been determined, and the need to support local considerations may have recently become more prominent.
- To gain the advantage of a broad base of potential suppliers, the utility may want to evaluate coals from more distant resources. The additional resulting transportation costs may be recaptured by savings resulting in a more competitive market. In this instance, considerations will be given to broadening the coal specifications to accommodate a number of new coal supplies.
- **Plant Engineer.** Plant engineers are continually faced with the decision of what equipment changes or modifications are required, what impact will they have on reliability and performance, and are they justifiable and cost effective. The following are a few concerns that typically arise.
 - Should the equipment be modified or added to ensure personnel safety?
 - Will equipment/system reliability and/or life-span improve with a modification or addition?
 - Can equipment/system performance and efficiency be improved?

In the case of the last two items, the high cost of the initial investment, equipment repairs, down time, and labor rates demand that the benefit-to cost ratio of each activity be evaluated carefully, considering all aspects. For these two instances, the CQE can be employed to assist in determining the benefit-to-cost ratio and the performance consequences of equipment modifications/additions. In some cases deficient performance does not limit generation, and increased capacity would only be negated by some other marginal or deficient equipment system. In other cases, the cost of the modification/addition could not be recovered by an increase in performance. And, still in another case, the cost to improve the system can be fully justified by an increase in equipment system capability and a positive effect on other related systems.

Available Applications are prominently displayed in CQE's user interface, and feature:

- A toolbox displays each of the four specialized applications available to the user.
- As each application is selected, CQE will display a log of prior and current analyses (analogous to a computer "run") in the window at the lower right of the screen.
- Additional information about either the application itself or a specific analysis is shown in the window on the upper right.

Applications facilitate sharing of data and knowledge between users and various analyses by utilizing one consistent set of tools and data to perform different types of analyses. Applications contain the "intelligence" necessary to guide the user

through an analysis by providing instructions as to what order things should be performed and what data or information are needed to successfully complete the analysis. In addition to providing the control logic for an analysis, the Application will provide a visual "roadmap" via on-screen diagrams. If user elects, additional roadmaps are displayed for any step warranting further explanation.

CQE also offers other sources of flexibility. It accommodates either individual or networked PCs and is flexible enough to employ English or metric units, different monetary systems, and international power plant technologies. Reports can be tailored to meet company- or project-specific needs.

The Second Dimension: Advanced Technical Models and Performance Correlations

CQE marks a significant advance in the sophistication of technical models available within a single, integrated environment. CQE builds on and integrates existing models to support both more detailed and broad analysis of fuel decisions.

CQE builds on existing correlations from worldwide R&D on the impacts of coal quality for specific parts of the total power generation system. In addition to CQIM, CQE interfaces with other industry-leading computer models. EPRI's Coal Quality Information System (CQISTM) provides a national database of coal quality information. Similarly, capital costs and performance assumptions for FGD installations and NO_x retrofits are developed from EPRI's FGDCOSTTM and NO_xPERT model results.

CQE lets users customize their software to further enhance the accuracy of analyses. Additionally, CQE will allow the user to graphically configure its system, plant, and unit equipment systems to match actual configurations present. CQE will also configure equipment models for users based on limited information, enabling users to begin applying the software immediately.

This groundwork of established models is complemented by new and enhanced models derived from bench-, pilot-, and full-scale test programs. These test programs, which allow coal-related effects to be distinguished from operational or design impacts, are among the most extensive of their kind ever conducted to relate power plant performance and emissions to coal quality. Six full-scale power plant test burns supplied important data to verify and expand CQE models.

Slagging and fouling phenomena have been extensively investigated in the program to allow CQE to predict how slagging and fouling in boilers and convection passes is likely to occur and how such deposits effect unit performance and load capability. CQE's innovative slagging and fouling model evaluates the effects of unit load, operation, and coal quality to predict heat transfer and ash deposit growth, strength, and removal.

CQE users can establish coal ash behavior by using conventional American Society

of Testing and Materials (ASTM) analyses or a new approach based on Computer Controlled Scanning Electron Microscopy (CCSEM). CCSEM provides additional, specific information on coal and mineral size, associations, and abundance not obtained through ASTM analyses.

The Third Dimension: Advanced User Interface and Network Awareness

Because the CQE will be dealing with a large amount of data and trying to satisfy a variety of specialized users, it is important that the interface to the program be very user-friendly, yet sophisticated enough to address each user's needs.

As discussed previously, CQE's application framework navigates users through an analysis, making CQE's user interface fundamentally different from interfaces found on traditional engineering, environmental, and fuel purchase models. By applying different visual road maps to different analyses, CQE meets the specific needs of diverse users by:

- Prompting the user to select or enter appropriate data about plant or equipment configurations, coals, and generation requirements.
- Displaying additional, more detailed road maps for subsequent steps, as needed.
- Managing the sequence in which data are entered and calculations performed.
- Seamlessly sharing plant, equipment, coal, and performance data among CQE users.
- Allowing users to build on results of previous analyses.
- Providing interactive displays of results that allow users to better understand results.

The CQE graphical user interface (GUI) will employ all various screen elements currently found in modern windowing environments such as windows, menus, and dialog boxes. Icons, bitmaps, and other graphical elements will be used to further enhance the CQE interface. In addition, CQE will take advantage of OS/2 notebooks to organize data and feature "custom" elements to manage international units and trace back explanations for key calculations. These will enable a vast amount of information to be displayed in a logical, consistent manner. Tables, graphs, and other professional business graphics will round out the user interface. For example, business graphics will be used to allow the user to compare economics of alternative fuel strategies, "expand" graphic objects to break out cost components, or display other pertinent supporting data (such as key plant performance parameters, etc.)

CQE's ability to manage and integrate information allows CQE users to efficiently share pertinent data and knowledge. Even though fuel decisions affect nearly every aspect of power generation, the complexity/diversity of fuels analyses has traditionally led utilities to perform its various evaluations in isolation. Fuels buyers handle transportation issues and coal sourcing; plant engineers evaluate how individual coals behave in a unit; and environmental engineers address compliance

and disposal issues. Typically, each expert uses an individual set of assumptions, data, and tools to complete an evaluation, resulting in one-dimensional pictures of fuel-related costs.

CQE integrates these assumptions, data, and tools, creating a unique environment within which experts can efficiently and effectively share their knowledge and results, in a consistent, timely, and accurate manner.

The power of this environment is twofold. It not only centralizes all relevant information, it makes that information available to all other experts as appropriate. The end result of integrating a set of previously isolated analyses is a new capability that provides a complete picture of fuel-related impacts and costs.

This sharing of data and operations among all the different CQE applications will be made possible through the use of the object database (ODBMS). The ODBMS will handle the storage, management, and retrieval of all the objects in the system. It will guarantee the persistence and integrity of the objects. It will also handle the concurrent transactions that will occur as CQE objects are shared not only among different applications, but also among different users on a network. All this means that the CQE user does not have to worry about the complexity of managing all the data that is a part of the CQE program.

THE CQE PROJECT

The CQE is a product of an extensive coal quality R&D initiative. The CQE project includes testing, analysis, and software development. The CQE development is primarily funded by DOE and EPRI. The overall CQE project is managed by CQ Inc., and Black & Veatch is the project's primary software developer and manager of all software development efforts.

Testing and data analysis portions of the project are supported by a number of recognized industry specialists. Electric Power Technologies heads up the full-scale testing program; ABB Combustion engineering leads pilot and bench-scale testing, analysis, and algorithm development activities. Other project participants are listed below:

- Alabama Power Company
- Babcock & Wilcox
- Decision Focus Inc.
- Duquesne Light Company
- Energy and Environmental Research Corporation
- Fossil Energy Research Corporation
- Mississippi Power Company
- New York State Electric & Gas Corporation
- Northern States Power
- Pennsylvania Electric Company

- Physical Science Incorporated Technology
- Public Service of Oklahoma
- Southern Company Services
- Southern Research Institute
- University of North Dakota Energy & Environmental Research Center

CONCLUSIONS

CQE is designed with the future in mind. It's architecture is oriented toward customization, integration, and future expansion. By building on the capabilities of the CQIM; incorporating other industry-standard tools; working directly during development with the international community; utilizing the strengths of object-oriented design and programming; and employing other state-of-the-art computer tools, CQE should become the new international industry standard for when it is initially released in mid 1995.

SELF-SCRUBBING COAL: AN INTEGRATED APPROACH TO CLEAN AIR

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ABSTRACT

The Custom Coals advanced coal cleaning plant has been designed with a unique blending of existing and new processes to produce two types of compliance coals: Carefree Coal and Self-Scrubbing Coal. Carefree Coal will be produced by cleaning the coal in a proprietary dense media cyclone circuit utilizing fine magnetite to remove up to 90% of the pyritic sulfur and correspondingly greatly reduce the ash.

While many utilities can achieve full SO₂ reduction compliance with Carefree Coal, others face higher sulfur reduction requirements due to the higher sulfur content of their existing fuel supplies. For these circumstances, a patented Self-Scrubbing Coal will be produced by taking Carefree Coal and pelletizing limestone-based additives with the finest fraction of the clean coal. These technologies will enable over 150 billion tons of non-compliance U.S. coal reserves to meet compliance requirements.

This paper provides an update on the progress made by Custom Coals International and its suppliers and subcontractors during the past year. Progress has occurred in the design and procurement areas since September 1993 and in the construction work since late December 1993. The DOE issued a Finding of No Significant Impact (FONSI) in February 1994.

INTRODUCTION

Approximately 65% of all coal shipped to utilities in 1990 was above 1.2 lbs SO₂/MMBtu. Even though most of that coal had been cleaned in conventional coal preparation plants, it still did not meet the SO₂ emission limitation the Clean Air Act Amendments mandate for the year 2000. Most utilities have announced compliance plans involving either switching to lower sulfur coals from Central Appalachia or the Power River Basin or the installation of scrubbers. Fortunately, for those of us attempting to commercialize clean coal technologies, relatively few long-term decisions have been made in Phase I - i.e. fewer scrubbers are scheduled than initially expected and new coal contracts rarely extend beyond the year 2000.

Through new coal preparation technologies, two compliance coal products can be produced by Custom Coals International (CCI) from most of the non-compliance coals east of the Mississippi River. They are termed Carefree Coal™ and Self-Scrubbing Coal™.

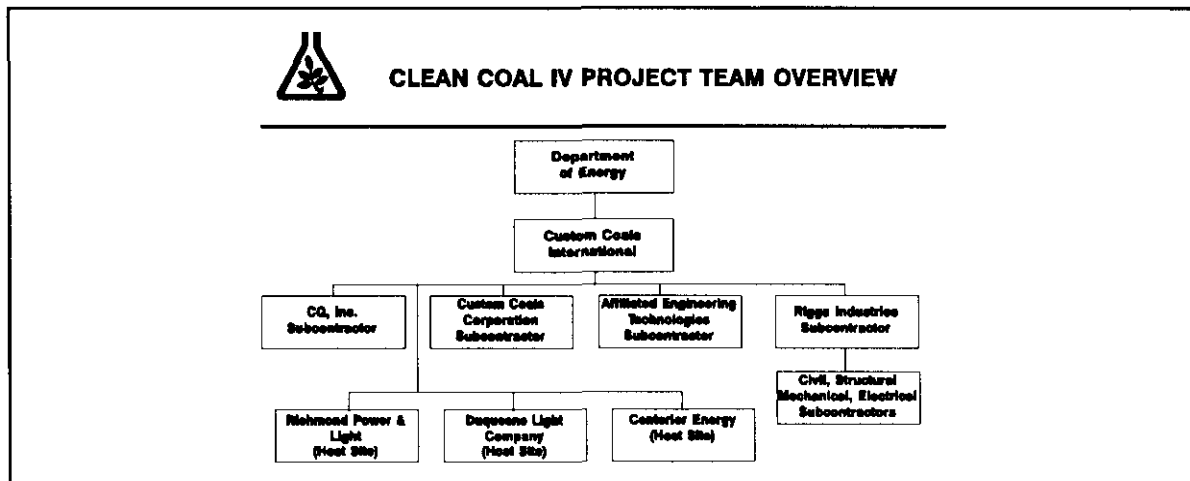
- Carefree Coal is produced solely through aggressive removal of ash and pyritic sulfur from non-compliance bituminous coal feedstocks. Carefree Coal is composed of coarse coal, fine coal and ultra fine coal. Some of the ultra fines may be briquetted.
- Self-Scrubbing Coal contains aggressively beneficiated coal with a limestone based additive. It is comprised of coarse coal, fine coal and briquettes. The additives are briquetted with the ultra-fine clean coal for convenience in handling.

For Self-Scrubbing Coal, the reduction of sulfur to compliance levels occurs in two stages. Pyrite, an iron-sulfur compound, is first removed by aggressive coal beneficiation. Sulfur dioxide, generated in the boiler from the coal's organic sulfur and residual pyritic sulfur, is then captured by the additives.

Carefree Coal and Self-Scrubbing Coal meet the year 2000 sulfur dioxide limitations. They are derived from local coals and, therefore, are compatible with the boiler; they are priced

competitively with compliance coals imported into the local region; and no capital investment is required by the utility. The net effect of CCI's technologies is that they revalue many noncompliance reserves to compliance reserves.

The objective of our Clean Coal Technology program is to design and construct a 500 ton per hour coal cleaning plant equipped with our unique and innovative coal cleaning technology which will produce competitively priced compliance coals. These coals will then be test burned at three commercial utility power plants to demonstrate that these coals can meet the Clean Air Act Amendment sulfur reduction requirements.



Custom Coals, which has overall project management responsibility, has assembled an exceptional team for this project. Associated Engineering Technologies, will design and Riggs Industries will manage the construction of the demonstration plant. CQ, Inc., will test and operate the demonstration plant and manage the power plant field tests. A project management committee of senior executives from the participating companies will oversee project progress and performance.

The project costs and timetable are shown below. The preparation plant will be located in Somerset County, Pennsylvania. The host sites for the test burns are located in Richmond, Indiana, Cleveland, Ohio and Pittsburgh, Pennsylvania.

	Dates	Proposed Costs
<i>Pre-award</i>	October 1991 - October 1992	\$736,969
<i>Project Definition</i>	November 1992 - August 1993	2,000,000
<i>Engineering & Construction</i>	September 1993 - April 1993 July 1993 - March 1994	49,200,000
<i>Operation</i>	May 1995 - March 1996	37,248,062
	TOTAL	\$89,185,031

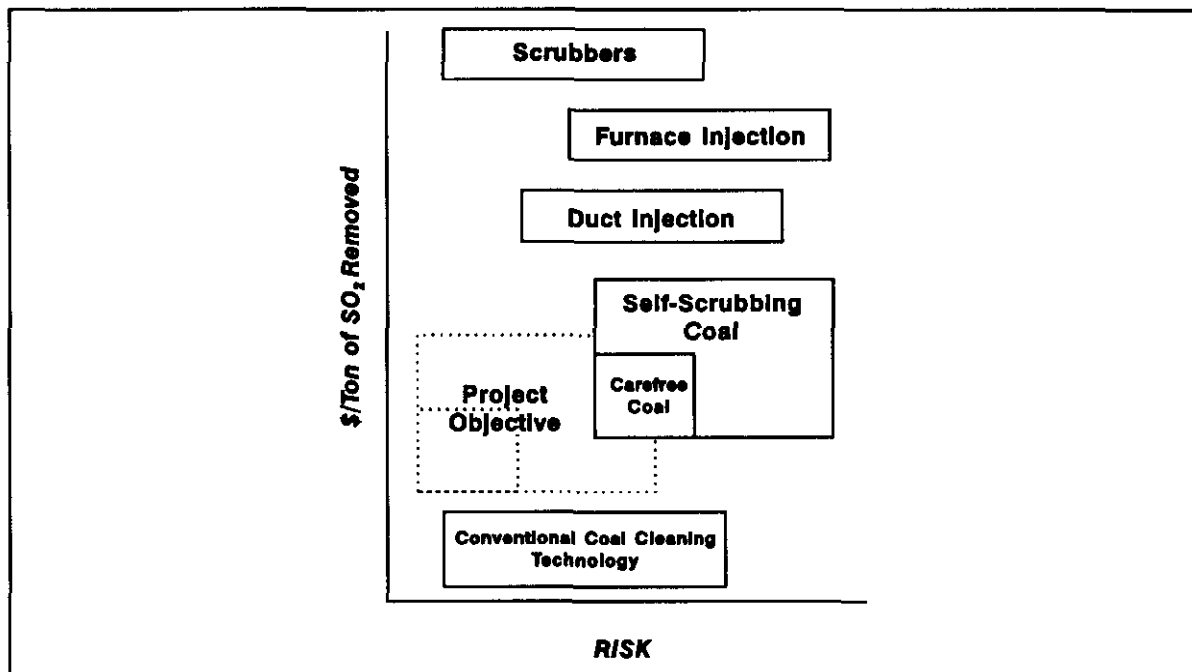
HISTORY OF TECHNOLOGY DEVELOPMENT

The Carefree Coal and Self-Scrubbing Coal technologies were developed through the proof-of-concept stage by Genesis Research Corporation, a small research and development company headquartered in Arizona. Dr. James Kelly Kindig, the inventor of the technology, had begun work on the technology in the late 1970's. A concerted effort to develop the products for commercial use began in the early 1980's. Funding during this stage of development was provided by equity raised from individual investors.

In 1988 Duquesne Light Company agreed to fund pilot scale testing of the technology. Cleaning tests in 2-inch cyclones were performed at CQ, Inc. and small-scale combustion testing occurred at Energy and Environmental Resources. The pilot scale test results supported Genesis Research claims of being able to reduce sulfur levels by up to 80%.

Given the encouraging pilot scale test results, in 1990 Duquesne agreed to fund commercial scale tests. Throughout 1990 and early 1991, a \$2 million test program was conducted and documented. All unique aspects of the coal cleaning technology were tested at commercial scale equipment sizes at CQ, Inc. Fine magnetite was prepared by Hazen Research, the cyclones were manufactured by Krebs Engineers and the magnetite recovery scheme was tested by Eriez Magnetics. The coal cleaning results in 10-inch cyclones substantially duplicated the performance achieved in the earlier 2-inch cyclone work. Combustion testing in 600,000 Btu/hour boilers at Energy and Environmental Resources also confirmed the earlier smaller scale results on sulfur capture in the boiler.

The full-scale demonstration provided by the Clean Coal Technology Program will provide the opportunity to blend all of the innovative aspects of the technology and prove the effectiveness of Self-Scrubbing Coal in reducing emissions. The demonstration will also prove the cost-effectiveness of the technology, paving the way to full commercialization of Self-Scrubbing Coal. The following Chart shows the various competing technologies for sulfur reduction in a format to show the Cost versus Technological Risk relationship. Based on current knowledge Carefree Coal and Self-Scrubbing coal are attractive options. By conducting the Clean Coal Technology demonstration, CCI expects to demonstrate an even better Cost/Risk relationship and convince the utility market to purchase these products.



PLANT DESIGN

The preparation plant will be located in Central City, Pennsylvania, Somerset County, at the site of the existing idled Laurel Preparation Plant built in the late 1970's by Consolidated Coal. A substantial percentage of the handling facility infrastructure will be refurbished and reused. The preparation plant building itself will be demolished and replaced. The site will include the following sections:

- Raw Coal Handling - The site will be equipped to receive coal by truck. The raw coal handling system consists of a truck dump, raw coal conveyors, two 15,000 ton stockpiles and a rotary breaker.
- Coarse Coal Circuit - A conventional heavy media cyclone circuit is used to clean the coarse material defined as 1½" by 1mm. The circuit is operated to remove very clean coal using a 1.30 specific gravity float and refuse material using a 1.75 specific gravity sink. The middlings material (1.30 sink by 1.75 float) is crushed and proceeds to the Fine or Ultrafine cleaning circuit depending on the resulting coal size.
- Fine Coal Circuit - In advance of the fine and ultra-fine cleaning circuits, a classifying cyclone circuit is used to remove the -500 mesh material consisting primarily of clay slimes. The fine coal cleaning circuit utilizes both a spiral concentrator and redesigned heavy media cyclones to achieve effective cleaning in the 1mm by 150 mesh size fraction. This heavy media circuit utilizes ultrafine magnetite to improve separation efficiency.
- Ultra-Fine Circuit - The ultra-fine magnetite and redesigned cyclones are also used to clean the 150-500 mesh material. The magnetite recovery system uses barium ferrite and rare earth magnetic separators to recover the ultra-fine magnetite.
- Coal Drying/ Pelletizing - Sorbent is mixed with ultra-fine clean coal which is then thermally dried and briquetted.
- Clean Coal Handling - Clean coal proceeds on a collecting conveyor through an automatic sampling system and onto three clean coal silos (5,000 tons each). From the silos, either trucks or unit trains can be loaded. The plant has access to a Conrail siding on site.

CURRENT PROJECT PROGRESS

Affiliated Engineering Technologies Inc. (AET) signed a contract to perform the construction engineering for Custom Coals International, Inc. (CCI) No. 1 Plant on August 30, 1993. AET mobilized on September 7, 1993 and commenced working on the project. The Master Project Schedule was reviewed with respect to the Work Schedule for the construction engineering and tentative milestone dates were established. Purchase orders were issued for major process units to provide design drawings for the engineers. No manufacturing was allowed until DOE issued the Finding of No Significant Impact (FONSI).

By December 1993 the site was ready for foundation installation. A subcontract was placed with Somerset Steel Erection to perform the Site Preparation and the Foundation Installation for the Preparation Plant. Site preparation drawings had been issued and the prep plant road would be installed to allow the contractor to move in the heavy equipment. Design and drawings for the preparation plant trench and pump foundations were completed. The structural system for the preparation plant as well as the roofing, siding, and platework design were also started. The general arrangement drawings for the stockpile and reclaim tunnel was completed. Equipment purchases were continued.

The winter weather became a hinderance in January and February and made field progress difficult and construction work was suspended for a week in February.

By the end of January, however, the ground of the building site was excavated and some foundations were dug. The beginning of February began with the pouring of foundations and piers (121.5 cu yards) as well as the forming of several grade beams. Work in the second week of February was brought to a virtual standstill due to the inclement weather. The DOE issued the FONSI in mid-month. By the end of February form work was completed and concrete poured for additional grade beams and several column foundations. A purchase order was placed with Cives Steel for the fabrication of all structural components.

Three main areas of design and drafting work were concentrated on during the month of March. All of these disciplines were concentrated in the Preparation Plant Building proper. The most significant concentration of effort was put forth in the completion of the remainder of the

structural steel. Approval of over 300 detail sheets from Cives Steel were completed and returned for modification and/or released for fabrication.

The other two areas of concentration in the Preparation Plant Building were Electrical and Piping design. All the instrumentation work for the entire project had been completed. In addition to the Preparation Plant Building, work had been completed in the truck dump foundation retaining walls, and reclaim tunnel.

By the third week of March approximately 650 cu yards of concrete had been poured and some 62,000 lbs of reinforced steel placed for the preparation plant. The elevator pit floor was also poured. Lincoln Contracting & Equipment Co. was awarded an order to fabricate all the steel sumps in the Plant and a subcontract to refurbish the existing on-site warehouse. This subcontract also included the general site clean-up work of all trash and miscellaneous old parts left from the previous plant operations.

Inclement weather also halted work for a few days in the middle of April. But highlights during the month of April include a total redesign of the Raw Coal Reclaim tunnel, performed to reduce the cost of construction to the budgeted amount.

Layout , digging, form work and pouring of concrete was completed for several sump and pump bases by the third week of April. Conduit sleeves were dug for underground utilities and concrete poured by month's end. Subcontracts were awarded to Somerset Steel Erection (SSE) for the plant Structural, Mechanical erection and for the Thickener/Densifier Tank installation.

Construction engineering progress for the month of May centered around the completion of the structural work on the Preparation Plant and the start of the ancillary building structures. A 90 ton crane moved onto the job site. The grounding for the high voltage line was installed. By the first week of May pumps and screens were delivered to the site. The second week in May completed a concrete pour of the plant floor (52 cu yards) and placed Acco drains, expansion joint and screed key. Also, the first load of structural steel was delivered from Cives (43,629 lbs) and the first of the structural steel erected. Also, steel tanks from Mine Sales & Service,

sumps from Lincoln Contracting and screens from Linatex were delivered to the site. In addition the electrical bid package was prepared and ready for bid in June. By month's end the vacuum pump foundations were poured. As of May 27 SSE received 516,536 lbs of structural steel and had erected 273,385 lbs.

Stone was placed and the final section of plant floor was poured in the first week of June, thus completing the final plant floor section. The thickener crew did the lay out work for the excavator and form work for the thickeners. Cast & Baker, the site prep subcontractor to SSE, spread, dried and graded wet material at the northeast corner of the job site, thus completing the final grading at the area north of the tanks and all contract work. By the middle of the month SSE's thickener crew laid out two thickeners for excavation and eventually formed and poured the first tank. To date SSE had received 814,935 lbs of structural steel and erected 551,350 lbs. Also they installed 4,884 square feet of steel decking and 72 feet of stairs.

To date, final drawings have been issued to support the following areas of construction:

- Site work, including grading at all locations
- Road work providing North, South and East access as well as parking area
- Foundations for the preparation plant including ground floor and all pump and sump foundations to facilitate steel erection
- Building steel for the preparation plant
- Underground utility for sewers, drainage and electrical conduit
- Raw coal receiving, unloading and storage

**TECHNICAL SESSION 6:
INDUSTRIAL APPLICATIONS**

Co-Chairs:

Steven J. Heintz
Pittsburgh Energy Technology Center
U.S. Department of Energy

Robert Ruether
Morgantown Energy Technology Center
U.S. Department of Energy

Jeffrey S. Summers
Office of Clean Coal Technology
U.S. Department of Energy

THIRD ANNUAL CLEAN COAL TECHNOLOGY CONFERENCE
THE INVESTMENT PAYS OFF
SEPTEMBER 6-8, 1994, CHICAGO, ILLINOIS

CONTINUING U.S. INTEREST
AND
EXPORT OF
RECOVERY SCRUBBER
POLLUTION CONTROL TECHNOLOGY

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ABSTRACT

The Recovery Scrubber flue gas scrubbing and industrial waste pollution control system developed by Passamaquoddy Technology L.P. (PTech) and built under Round II of the DOE Innovative Clean Coal Technology Program (ICCTP) is now owned by, and continues to serve the host plant, the Dragon Products Company Inc. cement plant in Thomaston, Maine. The ICCTP final reports have been submitted and the project has been successfully completed.

Domestic and International marketing efforts by PTech have resulted in several initial plant evaluations, economic feasibility studies, and progressed into two preliminary design efforts. This paper presents information on the type of installations currently being reviewed by PTech, i.e. cement industry, pulp and paper industry, power, or waste to energy industry, and how the Recovery Scrubber process is expected to interface with the various facilities.

Also discussed are the challenges to successful marketing faced by PTech. Implementation of environmental regulation by the Federal government is, at best,

hebetudinous. Surv:
Government assista
is a challenge.

INTRODUCTION

The Recovery Scrubt
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forum previously.
demonstration plan
continues to serve
the community.

Project Cost

The final project cost is \approx \$17,558,000.

Project Duration

Construction began in April of 1990. The process was first operated on December 21, 1990. The operating period began on August 20, 1991. The Final Report was submitted in February, 1994, and the project is now complete.

Project Disposition

The project will continue to be operated by Dragon Products Company Inc. at the Thomaston, Maine plant.

The Technology

The technology is a wet flue gas desulfurization process that uses waste (fly ash, cement kiln dust, incinerator ash, biomass ash, and other materials) as the chemical scrubbing reagent. Useful by-products that minimize or eliminate the need for landfill disposal of spent scrubber products are produced by the scrubbing reaction. Tipping fees for consumption of waste produced by others, sale of useful by-products and emission credits, and "fee for service" pollution control, generally allow profitable operation of the scrubbing process. Consequently it is offered to potential users as an "over the fence", own-operate service by PTech.

The technology is more fully described in Appendix A.

This paper discusses the current technology export activities of PTech and gives examples of combustion facilities where preliminary design has been completed or where systems are currently undergoing feasibility study/preliminary design.

THE RECOVERY SCRUBBER AND INDUSTRIAL POLLUTION CONTROL - AN OVERVIEW

During use of the Recovery Scrubber process flue gas scrubbing is coupled with consumption/elimination of waste materials, and production of salable by-products. The resulting environmental benefits from use of the process are,

therefore, not limited to flue gas clean-up. They include conversion of fly ash, biomass ash, or incinerator ash into desirable raw material for cement manufacture or for other uses. These uses in turn result in production of high value potassium based agricultural fertilizers, either potassium sulfate or potassium chloride. Use of these alternative sources of raw material further result in elimination of landfill disposal of certain wastes and conservation of valuable landfill space.

Industrial pollution control is a multifaceted endeavor where more than one pollutant may be controlled, more than one industrial facility may be involved, and more than one benefit may be derived. It is a potentially complicated effort in which each participant may reap significant economic and environmental benefit.

CURRENT FEASIBILITY STUDY/PRELIMINARY DESIGN PROJECTS IN THE UNITED STATES

The following discussion presents information on possible U.S. and foreign projects with which we are currently involved. Some of the projects discussed have progressed from initial evaluation, to feasibility study, through the preliminary design stage, to the point we are waiting for a contract to proceed. Some are still in the feasibility study stage where we work with owners to provide initial cost vs. benefit analysis. Some are very new project prospects which are not yet well defined, but which may become active projects between the writing and the presentation of this paper.

Hazardous Waste Burning Cement Plants

Several cement plants in the U.S. currently burn hazardous waste liquids (some also burn hazardous waste solids) and have significant potential for emission of pollutants. These may include particulate, sulfur dioxide, and HCl, as well as unburned hydrocarbons (dioxins, etc.) and toxic heavy metal vapors such as mercury, lead, cadmium, selenium, thallium and others. The U.S. EPA is currently reviewing the status of some wastes derived from these activities (see section on Regulatory Drivers below).

Hazardous waste burning cement plants are useful as a means for disposal of hazardous waste liquids generated by industry, but as a consequence of their fuel use options, they will require effective pollution control.

Preliminary Design

Preliminary design has been completed for one U.S. cement plant which uses hazardous waste as its primary fuel. For several plants where hazardous waste is a secondary fuel we have completed initial evaluations. These evaluations will presumably lead to preliminary design and/or feasibility studies if the U.S. EPA determines that CKD from cement plants burning hazardous waste is hazardous. The following example refers to the plant using hazardous waste as the primary fuel and represents the general situation for hazardous waste burning plants.

Waste cement kiln dust (CKD), generated during operation of a hazardous waste burning cement plant, will be used as the flue gas scrubbing reagent in one operating scenario which has been presented to plant management. In another scenario, waste CKD will be used and augmented with previously landfilled CKD. In still another, waste CKD and previously landfilled CKD will be used along with added purchased alkali. Each case has a somewhat different economic outcome, but each will provide a significant return. None will require material to be landfilled.

Processed CKD, after use as scrubbing reagent, will be returned to the cement plant raw material preparation system where it will become part of the total raw material entering the kiln, and where it subsequently will become cement. The soluble alkali portions of the CKD will be dissolved, crystallized, and recovered for sale as one or more by-products. The principal operating difference between the three scenarios above will be the rate, in tons per hour, at which recovered CKD will be returned to the cement plant as raw material feed.

The hazardous waste fuels used at the subject plant contain a significant quantity of lead. The lead is volatilized within the kiln system, travels through the kiln, and exits with flue gas to the particulate control system, an ESP. The CKD collected, therefore, contains most of the lead that has entered the kiln. When processed CKD from the Recovery Scrubber is returned to the kiln as raw material, the lead is returned also. This will cause a continuing build-up in the lead concentration within the system if it is not short-circuited in some way. To intentionally accomplish the short circuit, the lead content in raw material (raw material plus recovered processed CKD) is allowed to rise. Then a small side stream is diverted to a lead recovery system where lead is selectively dissolved, separated, reprecipitated, and collected as an additional by-product. The non-lead portion of the side stream is returned to

the raw material system as feed.

Project Status

Final design and installation of the system on any U.S. hazardous waste burning cement plant will await regulatory determination of the nature of CKD by the U.S. EPA (see section on Regulatory Drivers below).

Pulp and Paper

Both gaseous emissions and solid combustion residues (ash) from the manufacture of pulp for paper making, along with a number of caustic process chemicals and mill wastewater can be effectively dealt with by the Recovery Scrubber. Two pulp and paper mills are currently evaluating this process with intent to reduce their fuel cost and eliminate landfilling a variety of materials. One prospective project will serve as a description. The mill is located in Maine and burns oil, wood waste, coal, and tire derived fuel in a proportion that minimizes fuel cost and keeps emissions of SO_2 within current State mandated limits. Ash from these boilers goes to landfill. A new facility for de-inking of recycled fiber will soon contribute ash to the mill solid waste stream, doubling the quantity going to landfill.

Installation of the Recovery Scrubber will impact the mill in several ways. When flue gas is scrubbed the allowable fuel sulfur content can be significantly increased and fuel cost decreased. This is because a high sulfur fossil fuel can replace low sulfur fossil fuel and high priced wood. Ash from any plant boiler can be incorporated in the scrubbing reagent whether or not flue gas from that boiler is scrubbed. That is, flue gas from a wood fired boiler may not need to be scrubbed but ash from such a boiler is useful. Ash from off-site can be added, if needed, to achieve stoichiometric balance with fuel sulfur. Potassium sulfate will be produced as a by-product, and spent ash will be transported to a cement plant (the same one hosting the demonstration project) for incorporation in raw material.

The result will be cleaner emissions, lowered fuel cost, elimination of the landfill and its future liability, marketable SO_2 emission credits, and production of valuable by-products (kiln feed, K_2SO_4 , and distilled water).

Utility Cooperation

PTech is currently discussing formation of a joint venture company (JV) with an electric utility. If the ongoing opportunity evaluation warrants, the JV would be created to interface with existing boiler operators in one or more of a variety of ways.

NON-U.S., TECHNOLOGY EXPORT

PTech has been evaluating overseas opportunities for some time. We have learned a great deal, but so far do not have a contract to install another system. The prospects, however, look good.

Cement Plant in Asia

We are currently involved in preliminary design and feasibility study for a scrubber on a cement plant in Taiwan.

Waste To Energy (WTE) Ash in Europe

Landfill disposal of ash from incineration of municipal trash in Europe is costly because of social opposition (NIMBY) and dwindling landfill space. Trash ash may contain significant quantities of soluble salts (NaCl and others) as well as compounds of toxic heavy metals that are soluble and leachable by groundwater. The quantity of heavy metals is strongly related (inversely) to the local success of recycling efforts. Some ashes, for example, contain several percent lead. Others contain well below one percent lead.

We are currently working with companies within Germany who deal with ash generation; ash transport, treatment and disposal; and cement manufacture. A combination of these companies has the potential, by installation of a Recovery Scrubber on a cement plant, to convert ash into raw material feed for the cement kiln and eliminate ash landfilling and, while charging lower cost tipping fees than those currently paid for landfilling, operate at a profit.

WASTE TO ENERGY (WTE) ASH IN THE FAR EAST

Discussions are currently underway to address use of the Recovery Scrubber technology for treating ash from combustion of municipal waste. This possible use includes the potential to install the technology on trash incinerators, and to install the system on a cement plant and transport incinerator ash to the cement plant for treatment and incorporation into cement raw material.

CHALLENGES

US-Regulatory Drivers

Government regulation of pollutant emissions drives installation of pollution control equipment. Therefore, purchase by industry of pollution control equipment, and ultimate success of the Clean Coal Technology Program rests (except where export of technology is possible) entirely in the hands of the Federal or State Governments and their pollution control efforts.

Several regulatory determinations have been, or will be made as a result of the 1990 Amendments to the Clean Air Act. Some of these will tend to encourage use of pollution control technology. Affected compounds include sulfur dioxide, nitrogen oxides, carbon dioxide, hydrochloric acid, toxic heavy metals, and toxic organic chemicals. There are interests other than smokestack emissions.

One of the environmental arenas currently being scrutinized by the U.S. EPA is the fate of waste cement kiln dust (CKD) which is generated by a majority of cement plants during the manufacture of cement. CKD is one of the high volume wastes initially addressed by congress under the Resource Conservation and Recovery Act (RCRA). Congress enacted RCRA in October, 1976 and asked that EPA promulgate certain regulations dealing with hazardous wastes. EPA proposed to defer a number of "special wastes" until information could be gathered and a ruling made. CKD was one of these "special wastes". Here in 1994, eighteen years later as of October, 1994, the ruling has yet to be made by EPA. That speedy response by EPA is, if nothing else, "special". If the ruling is ultimately made by EPA, and if that ruling determines that either all CKD or CKD generated at plants burning hazardous waste, is hazardous in nature, then there will have to be technology to deal with it. The Recovery Scrubber is a suitable technology and awaits a timely government decision.

Learning Curve - Government Assistance Availability

Who Is Who, What They Do

A significant challenge, particularly, but by no means exclusively, with relation to export activity, is learning who the various U.S. Government export assistance agencies are, what they do, and where and why they do it. It is easy to see why existing large companies have in house staff to deal with export assistance. For the small, new company it is a daunting task, a challenge.

APPENDIX

DESCRIPTION OF THE TECHNOLOGY

General Information

Detailed description of the technology has been given elsewhere [see references at end of paper.] The following general information is provided as it relates to the current discussion.

The Recovery Scrubber process uses alkaline waste materials as scrubbing reagent. These may include fly ash, waste cement kiln dust, incinerator ash, biomass ash from wood fired systems, and other similar wastes in solid or liquid form. Use of these wastes has the advantage of providing low cost reagent and income from tipping fees for consumption of waste. It also has the advantage of reducing, or in some cases eliminating, the volume of waste that must enter a landfill, thereby conserving valuable landfill space. Figure 1. illustrates basic process flows and system components.

Chemical Reactants

The alkali metals sodium or potassium, rather than the alkaline earth metals calcium or magnesium, are used for combination with sulfur from flue gas. Because calcium sulfate is not formed there is no gypsum scaling within the scrubber and no requirement for disposal of gypsum or scrubber sludge. Sodium or potassium form soluble compounds with recovered flue gas sulfur (sulfate) or hydrochloric acid. They will not cause scaling, and both potassium sulfate and potassium chloride are highly valued marketable by-products.

Solids Recovery

Calcium present in the waste will react to form calcium carbonate (limestone) by combining with carbon dioxide from the flue gas. This results in scrubbing of carbon dioxide from the flue gas. The product, essentially limestone, makes the spent reagent useful as raw material for use in cement manufacture or as starting material for manufactured aggregate for use in asphalt or concrete, thus

eliminating the need to dispose of spent material in a landfill. Both the environmental advantage and the cost advantage of producing a useful by-product rather than a waste sludge are important.

Energy Recovery

Waste heat from the flue gas being scrubbed is recovered and used in the Recovery Scrubber process. Recovery of the waste heat allows for economical recovery of the soluble alkali sulfate salts by simple evaporation of solution and crystallization of dissolved solids.

Alkalis Recovered

Recovered alkali sulfate salts are removed from the process as solid salt crystals of potassium sulfate or sodium sulfate. In situations where chloride is present in the waste used as reagent, or in the flue gas being scrubbed, the product will include potassium chloride and/or sodium chloride, or diatomic chlorine may be produced for sale if desired. The various salts produced can be separated to enhance their resale value. All of these products have resale value. Potassium sulfate has the highest value at \$200-\$240 per ton wholesale or up to \$400 per ton retail.

Installation and Operation

The scrubbing process was installed with minimal impact on the operating cement plant. It is an "end of the pipeline" retrofit process. The only interconnect to the cement plant that might have curtailed operation is the physical tie in of the flue gas handling duct, however, the tie in was made during a routine kiln shut-down with no impact on kiln operation.

The Recovery Scrubber operates as an integrated unit, therefore, all subsystems in the process were operable at the outset with the exception of the crystalline product pelletizing equipment which was not necessary for operation.

The process control system is by computer with operator interface and ability to override as necessary. The control panel and display are located on the desk of the cement plant kiln operator for his use. No additional operator is necessary.

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Paper Presented at the
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Status of the Demonstration of
Pulse Combustion In Steam Gasification

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ABSTRACT

ThermoChem's Clean Coal Technology project is a unique gasification process that uses indirect heating by combustion tubes immersed in a fluidized bed producing medium-Btu gas without needing an oxygen plant.

The concept of using pulse combustion tubes as an indirect heat source was developed by Manufacturing Technology Conversion International, Inc. (MTCI), who have licensed the technology to ThermoChem.

MTCI has completed a successful field testing of the pulse indirect heater (72-tube bundle) in a pulp and paper mill sludge/rejects gasification at Inland Container Corporation, Ontario, California in 1992. There is another field testing project of the pulsed indirect heater well underway in a distillery effluent treatment application aiming at zero-discharge by Esvin Tech, in Tamil Nadu, India. A third field testing of a three-heater (each with 72-tubes) fluid bed system for black liquor recovery is in progress at Weyerhaeuser pulp mill in New Bern, North Carolina.

The proposed Clean Coal project is a scale-up of the pulse heater from 72-tubes to 252-tubes each. The Clean Coal gasifier would have 8 to 10 heater bundles to handle 300 T/D of dry coal.

Because of the large potential market for the ThermoChem process for the pulp and paper industry, the project was originally planned to be located in a Weyerhaeuser paper mill in Springfield, Oregon. After the project was selected under the Clean Coal Fourth round, ThermoChem requested DOE to move the project to the Caballo Rojo Coal mine site in Gillette, Wyoming to supply gas and steam for "K-Fuel," coal-upgrading plant that would be built by Enserv, Inc., an affiliate of Wisconsin Power & Light.

The K-Fuel process upgrades low-rank coals producing a high Btu containing solid fuel called "K-Fuel" (to be substituted in power stations as low sulfur coal), and also generates wastewater and off-gas both of which need to be treated before discharge. The ThermoChem gasifier can not only use K-Fuel wastewater and off-gas, but it can gasify the fine coal that is not marketable or usable by the K-Fuel plant. A preliminary test using K-Fuel effluent water and Caballo Rojo Coal fines was done in 1992 in MTCI's laboratory-scale gasifier facility in Santa Fe Springs, California at 20 lb/hr. This test showed that the organics in the K-Fuel effluent could be destroyed in the MTCI gasifier. A 252-tube bundle will be built and tested as part of the design verification in 1994. For design verification, a 72-tube pulse combustor heater unit was used at MTCI's Baltimore facility in February 1994. North Antelope mine coal from Gillette, Wyoming was gasified at both high temperature (1400-1500°F) and low temperatures (1200-1300°F) to verify gas and char yields.

MTCI/THERMOCHEM BIOMASS STEAM REFORMING TECHNOLOGY

Manufacturing and Technology Conversion International, Inc. (MTCI) is an energy conversion and environmental control development company focusing upon the development of innovative technology applications based upon the phenomenon of pulsating combustion. Generally speaking, combustion instabilities are not only undesirable from both performance and environmental considerations, but can result in mechanical failures in the combustor or the furnace (boiler).

Over the years, many attempts have been made to harness those pulsations for a variety of applications. Many failed, a few were successful from the standpoint of performance but could not compete favorably in the marketplace. Some, primarily gas-fired home heating units, are available today but sales have been very sluggish in comparison to standard home heating systems.

About eight years ago, MTCI came to the realization that these combustion instabilities could provide many benefits when converted into well behaved oscillations. The company envisioned a host of applications for "stable" pulsating combustors; at first for clean and effective coal combustion, then for indirectly heated gasification systems and coal-fired fluid-bed combustors and finally for environmental control devices primarily aimed at coal-fired power plants.

PRINCIPLES AND BENEFITS OF PULSE COMBUSTION

The process of pulse combustion results from combustion-induced flow oscillations that are intentionally incorporated in combustor design to achieve process and system advantages for various combustion and gasification applications. The benefits accruing from controlled combustor oscillations are enhanced heat release rates (compact equipment), mass transfer rates (higher reaction rates, yields), heat transfer rates (indirectly fired heat exchangers), and the ability to develop a pressure boost that aids in reducing parasitic forced and induced draft fan power. The process has ancillary environmental benefits in drying applications, ash agglomeration, enhanced sulfur capture by dry sorbents, soot blowing and filter/baghouse cleaning.

The pulse combustor type used by the MTCI and ThermoChem equipment design is based on the Helmholtz configuration (**Figure 1**). The basic configuration consists of an aerodynamic air inlet valve (fluidic diode), a combustion chamber, and a tailpipe (or resonance tube). The combustion chamber and the resonance tube comprise a Helmholtz enclosure having a quarter-wave resonant frequency. There are no moving parts (flapper valves) thereby making it ideal for coal combustion as well as for other solid, gaseous and liquid fuels. The selection of this configuration was made primarily because of its excellent suitability and reliability for coal burning.

In conventional coal burners (cyclone, vortex, bluff body, etc.) combustion efficiency is highly dependent on the flow pattern and the extent of the relative motion between the burning coal particle and the surrounding gases. As the coal particles burn, they become smaller and increasingly ash-laden (char) while oxygen concentrations are decreasing. Oxygen diffusion from the surrounding gas to the burning ash-laden char particles also decreases requiring additional residence time and turbulence to achieve higher carbon burnout. This is caused by a boundary layer of products of combustion (CO_2 and CO) forming a diffusion barrier between the oxygen and the smaller ash-laden coal particle. The entrainment prone nature of small particles, as carbon depletes from the burning coal particle, prevents significant relative motion between the particle and the surrounding gases, requiring the expenditure of high levels of parasitic power to create the flow patterns and forces necessary to drive the combustion process to completion.

In pulse combustion, the oscillating flow field, itself, provides high oscillatory relative motion between the burning coal particles and the surrounding gases. The boundary layer formed by the products of combustion, leaving the burning particle, is quickly swept away leaving little to no diffusion barrier as an impediment for oxygen reaching the burning coal particle. The reaction rate is, therefore, essentially kinetically limited rather than diffusion limited. Heat release rates can reach as high as 6 MMBtu/hr.cu.ft., more than an order of magnitude higher than in conventional combustion processes. This renders pulse combustors very compact and lower in capital cost. Combustion of standard grind pulverized coal has been achieved in 30 to 40 ms. In conventional coal burners, residence times in the order of $\frac{1}{2}$ to $1\frac{1}{2}$ seconds are required.

In conventional combustor and fire tubes arrangements, essentially all the heat is released by burning the fuel in the combustor. The heat is stored in the form of sensible heat in the flue gas which is at its peak temperature at the inlet to the fire tubes. This requires the use of a high-temperature material at the inlet region of the fire tube. As the heat is transferred from the flue gas through the fire tubes, the temperature of the flue gas monotonically decreases along the length of the tube. In this case most of the heat transfer on the flue gas side of the tube is convective. Radiant heat transfer may take place near the fire tube inlet if the gas is hot enough to be significantly radiant. In pulse combustion, however, not all the fuel burns in the combustion chamber but combustion persists down the resonance tubes (fire tubes) for a significant length in an oscillating flow field environment. Thus, for the same heat transfer duty, the inlet flue gas temperature to the resonance tubes is lower than in the case of conventional fire-tube systems, but the continued heat release from burning fuel in the resonance tubes maintains a higher bulk flue gas temperature than in the conventional case. Radiant heat

transfer will also maintain to a longer length on the flue gas side of the resonance tube. In addition to the enhanced radiant heat transfer component along the resonance tube, a large enhancement in the convective heat transfer component is also achieved due to the oscillatory flow field of the gases. The enhancement in convective heat transfer results from an increase in both the average velocity (caused by the combustion-induced pressure boost), and the superimposed oscillatory velocity component (scrubbing of the boundary layer).

Figure 2 represents experimental heat transfer data obtained on a gasifier combustor heat exchanger. The figure represents a comparison of experimental data with theoretical non-pulsating flow values. Actual enhancement of the heat transfer coefficient was about 3 to 5 times higher than that achieved by similar indirectly heated systems.

An important benefit of enhanced heat transfer rate is the ability of the reactor to support highly endothermic reactions such as the carbon-steam reaction. Rapid heat transfer to the fluidized bed material being processed results in very high rates of devolatilization and pyrolysis. This, in turn, results in the formation of char particles that are extremely porous with high reactivity. Steam reacts with the char to provide a synthesis gas mixture containing H_2 and CO . Devolatilization and gasification reactions are highly endothermic reactions. High heat transfer rates are therefore essential to support such endothermic reactions in an economically viable reactor with a reasonable throughput.

Pulse coal combustors, properly designed, have been established to be low NO_x generators. NO_x levels as low as 83 ppm (@ 3% O_2 in the flue) have been achieved by MTCI in pulse combustion of coal and in the 10-25 range when fired with natural or synthetic gases. There are a number of combustion process related characteristics of pulse combustion that are relevant to NO_x production. The rate of combustion in these devices is sufficiently high, with short residence times, such that NO_x formation is reduced. NO_x formation is endothermic with limited kinetic rates and hence the shorter the residence time, the less NO_x formation during the combustion process. The pulse combustion process inherently contains both flue gas recirculation and reburn characteristics. During a portion of the cycle of the pulse combustor, flue gas returns to the combustion chamber from the resonance tube mixing with the fuel and air prior to ignition by the hot combustion chamber inner surfaces to trigger the next portion of the combustion cycle.

The equivalent of reburn is caused by the burning of particles after they leave the combustion chamber. Measurements of temperature profiles along the combustor length suggested that 15 to 25 percent of the heat release takes place in the tailpipe. The flow environment in the tailpipe is also oscillatory providing an intense mixing during the reburn portion of the process, leading to further reductions in NO_x formed from both fuel-bound nitrogen and thermal sources in the combustion chamber. **Figure 3** gives the NO_x levels obtained in the 72-tube pulse combustor.

PULSE COMBUSTION APPLICATIONS

The following discussion addresses the hardware and technology applications based upon the essential principles of pulsed coal combustion. A summary of the related MTCI pulse combustion-based technology is provided in **Table 1**. For each application cited, process data

and/or hardware has been successfully acquired and operated. The presentation is intended to provide a perspective that relates to the available technology data base and equipment maturity.

Indirectly Heated Thermochemical Reactor and Processes

This technology is comprised of a fluid-bed reactor that is indirectly heated by a heat exchanger that is comprised of the multiple resonance tubes of a pulsating combustor as shown in **Figures 4 and 5**. In this design the multiple pulse combustor resonance tube heat exchanger is fired with a portion of the product gas produced in the fluid-bed reactor or other fuel available. The module has multiple aerodynamic valves.

The reactor is employed for a number of patented endothermic processes that are also listed in the table. The status of the technology is as follows. A commercially configured, full-scale heater module (5-8 MMBtu/hr) powering a 12-tons/day fluid-bed reactor (40 ft²) has been built, tested and demonstrated at the MTCI facility in Santa Fe Springs, California (**Figure 6**). This is a pilot unit that can be used at the facility for feedstock characterization, yield optimization and other system parameter information.

A smaller process development unit, 30-100 lbs/hr is also available at the Santa Fe Springs facility. This unit is primarily used for initial process development and characterization (all input and output streams).

A 17 ton/day gasification unit has been installed at the Inland Container Corporation facility at Ontario, California. This unit has been in operation since March 1992 and a long-term system test was conducted in July 1992. The system processes an industrial recycle paper mill sludge containing 50 percent solids, fiber rejects with plastic and old corrugated container lights (OCC). A photo of the system in operation is provided in **Figure 7**. **Tables 2 - 5** present the operating parameters for a 500-hour test on this unit. This unit was modified to process black liquor and was tested at Inland with liquor trucked from the Simpson-Samoa mill. After these successful field tests, this heater development unit was moved to MTCI's Baltimore, Maryland facility. NREL-sponsored straw or grass and woody biomass gasification tests and NSSC sulfite liquor tests for MEAD Container Board are planned for October 1993.

In addition, a 50 ton/day expandable to approximately 100 tons/day with the addition of two additional heat exchanger modules is being assembled at Weyerhaeuser's paper mill in New Bern, North Carolina (**Figure 8**). This unit processes black liquor from the pulping process, recovering energy from the lignin in the spent pulping liquor as well as process chemicals (sulfur and sodium) for reuse in the pulping process. A similar unit is now in operation for a bagasse-based spent liquor recovery process at an SPB pulp mill in Erode, Tamilnadu, India.

For coal gasification, ThermoChem, an MTCI licensee of the gasification technology, has been selected to negotiate a Clean Coal IV Demonstration Project utilizing the MTCI indirectly heated gasifier. The cost of the project, \$42,000,000, will be provided by the U.S. Department of Energy (\$18,700,000) and Enserv (\$23,300,000). Enserv is a subsidiary of the Wisconsin Power and Light Company. An overall material and energy balance for the process is provided

in **Table 6**. A simple schematic of the gasifier is shown in **Figure 9**. The tube exchanger bundles to the reactor contain 252 tubes each for providing the endothermic heat of reaction.

The versatility of the MTCI Thermochemical reactor/gasifier for processing a wide spectrum of carbonaceous materials can be derived from **Tables 7** and **8**. A generalized schematic of the process is shown in **Figure 10**. **Table 3** provides test data from lignite, subbituminous coal (Black Thunder, BT) and char as well as for a mild gasification process designed to provide a suite of gaseous, liquid and solid fuel products. **Table 4** provides data for a variety of biomass and waste materials including Refuse Derived Fuel (RDF) and municipal wastewater sludge. **Table 9** indicates the levels of dioxin and furan reductions achieved in the gasification of chlorine biomass wastes. The tests were conducted with a paper mill waste sludge feedstock.

A pilot-scale test took place from February 1 - 16, 1994 at the MTCI Baltimore manufacturing facility using North Antelope coal as a feedstock. In addition, progress on the 252-tube pulse combustor and test vessel continued.

Pilot-Scale Testing

A 72-tube pulse combustor and reactor were used during the February 1994 test. The feedstock was coal from the North Antelope mine in Gillette, Wyoming. The coal was characterized by Standard Laboratories, Inc. of Casper, Wyoming as follows:

Moisture	27.06%
Ash	5.28%
Sulfur	0.28%
Sodium	1.04%
HHV, Btu/lb	8,734

A process flow diagram is of the pilot plant test facility as shown in **Figure 11**. Two separate fluidized bed temperatures were tested.

In the first test, which was run for about 33' hours, the bed temperature was roughly between 1400°F and 1500°F. **Table 10** shows instantaneous readings during steady-state periods of operation.

The carbon level in the sand bed after 33' hours was only about 0.1 percent which shows a high carbon to gas conversion. The gas production rate shows that the energy from the gas produced is about 25 percent more than that of the coal fed. Due to the design limitations of the steam superheater, the pulse combustor was fired with 50 to 75 percent excess air at not more than 7.5 million Btu/hr. The high excess air caused excessive heat loss from the system. Therefore, the coal feed rate was limited by the amount of heating load it applied to the system. With a properly designed steam superheater, the firing rate of the pulse combustor should be approximately 8.5 million Btu/hr with less than 5 percent excess air.

During the second test, in which the test duration was about 6' hours, bed temperatures were between 1200°F and 1300°F. **Table 11** shows instantaneous readings during steady-state periods of operation.

The primary objective of the second test was to evaluate the char production at lower temperatures for export to iron reduction processes or to produce activated charcoal. The low carbon gasification efficiency indicates a high carbon production rate.

252 Tube Pulse Combustor Design

Detailed design continued for the 252-tube pulse combustor and test vessel. Several trial designs were examined. First, a rectangular pulse combustor was considered to provide maximum coverage of bed cross-section with tubes. This pulse combustor would have four 63 tube modules that would fit into a common combustion chamber and exhaust plenum. However, after discussion with Dr. Octave Levenspiel, Professor of Chemical Engineering at Oregon State University and a noted expert in the field of fluidized bed technology, it was decided that maintaining a large inventory of bed per tube within the fluid bed is of primary importance. Due to this decision, a round pulse combustor was deemed appropriate for this project.

In order to minimize heat loss from the water-cooled combustion chamber, the operating pressure of this circuit is to be 500 psig. This would raise the temperature of the cooling jacket to roughly 470°F. Due to this change, the water jacket section of the pulse combustor falls under the domain of ASME Code, Section I. Therefore, the outer portion of the combustion chamber jacket will be constructed of a membrane wall with inlet and discharge headers above and below the chamber.

Spring-loaded thermocouples will be used to maintain positive contact between the thermocouple and the tube. These thermocouples will be replaceable during operation of the pulse combustor for maintaining accurate temperature measurement.

The test vessel is shown in **Figure 12**. This vessel will be designed, constructed, and stamped in accordance with ASME Code, Section VIII, Division I for 30 psig pressure at the bottom of the reactor. This will allow a maximum freeboard pressure of approximately 15 psig.

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TECHNOLOGY	DESCRIPTION	APPLICATIONS
Indirectly heated thermochemical reactor	Multiple resonance tube gas-fired pulse combustor heating a fluid-bed thermochemical reactor	<ul style="list-style-type: none"> • Biomass steam reforming • Low-rank coal steam reforming/gasification • Black liquor recovery (Pulp & Paper) • Mild coal gasification • Catalytic steam re-forming of heavy end residual hydrocarbons • Sewage sludge steam gasification • Industrial sludge processing • Indirect drying • Toxic waste to energy processing • Steam gasification of RDF
Pulsed Atmospheric Fluid Bed Combustor (PAFBC)	A hybrid combustion system employing a pulse coal combustor and a fluid-bed combustor	<ul style="list-style-type: none"> • Clean combustion of low-quality crushed coal fuels
Tandem slagging pulse coal combustor	Two pulse combustors that operate in the slagging mode for ash rejection. The combustor operates out of phase to cancel pressure oscillations emanating from the tail-pipes in a decoupler/slag chamber	<ul style="list-style-type: none"> • Industrial, oil and gas designed boiler, retrofit for clean coal firing
Multiple-resonance tube coal-fired pulse combustors	Pulse coal combustor having one or multiple aerovalves and multiple resonance tubes	<ul style="list-style-type: none"> • Commercial boiler retrofit applications • Indirect-fired gas turbine

TABLE 1. SUMMARY OF MTCI PULSE COMBUSTION-BASED TECHNOLOGIES AND APPLICATIONS

TOTAL HOURS FOR PULSE COMBUSTOR OPERATION:	516 Hours
TOTAL HOURS FOR SLUDGE FEEDING:	432 Hours
TOTAL WEIGHT OF SLUDGE FED:	275,730 Pounds
AVERAGE SLUDGE FEED RATE:	640 lbs/hr

TABLE 2. SUMMARY OF THE OVERALL SYSTEM OPERATION FOR 500-HOUR TEST (JULY 1992)

<u>INPUT</u>	<u>lbs/hr</u>	<u>MMBtu/hr</u>
SLUDGE FED	500 - 900	2.30 - 3.2
FEED MOISTURE (% wt.)	50% to 75 %	
STEAM FOR FLUIDIZATION	1700	1.94
NATURAL GAS TO PC (based on LHV)	350 - 360	7.5 - 7.7
<u>OUTPUT</u>		
PRODUCT GAS	367 - 700	3.1 - 5.8
STEAM	4000	5.0
LOSSES	---	1.0 - 2.0

TABLE 3. TYPICAL MATERIAL FLOW SUMMARY FOR 500-HOUR TEST (JULY 1992)

AVERAGE BED TEMP. (°F)	1515	1470
GAS COMPOSITION	(%V)	(%V)
H ₂	34.7	44.3
CH ₄	11.6	5.4
CO	22.5	18.1
CO ₂	27.0	29.8
C ₂	4.3	2.5

TABLE 4. TYPICAL PRODUCT GAS ANALYSIS (JULY 1992)

FIRING RATE (HHV)	=	8.20 - 8.45 MMBtu/hr	
(LHV)	=	7.4 - 7.7	
FREQUENCY	=	62 Hz	
PEAK-TO-PEAK	=	4 psi	
FLUE GAS EMISSION, DRY BASIS			
<u>Conditions</u>	<u>#1</u>	<u>#2</u>	<u>#3</u>
O ₂ (%v/v)	1.4	1.8	0.3
CO (ppm)	23	0	97
NO _x (ppm @ 3% O ₂)	25	30	32
SO ₂ (ppm)	0.0	0.0	0.0

TABLE 5. PULSE COMBUSTOR DATA (JULY 1992)

	MASS (lb/hr)	ENTHALPY (KBtu/hr)	HHV (KBtu/hr)
INPUT			
Coal	35,714	300,000	300,000
Process Water	52,191	31,943	6,741
Boiler Feed Water	73,929	15,007	
Vent Gases	5,582	16,486	15,094
Combustion Air	127,044	0	
TOTAL IN	294,460	363,436	321,835
OUTPUT			
Product Gas	31,250	188,352	187,834
Steam @ 500 psi	33,202	41,466	
Steam @ 1150 psi	49,726	64,296	
Sulfur	332	1,322	1,322
Char/Ash	2,817	16,958	16,095
Solids from Scrubber	232	1,742	1,738
Water from Venturi Scrubber	17,489	739	
Condensate from H ₂ S Removal	1,450	48	
Flue Gas to Stack	157,916	17,766	
Heat Rejected in Cooler		24,117	
Heat Losses		6,630	
TOTAL OUT	294,414	363,436	206,989
CLOSURE, percent	100.0	100.0	
Cold Gas Efficiency	57.6%(HHV of Gas-HHV of Vent Gas)/HHV of Coal		
Overall Thermal Efficiency	80.9%		

TABLE 6. OVERALL MATERIAL AND ENERGY BALANCE FOR STEAM REFORMING OF SUBBITUMINOUS COAL

Feed Material	Lignite	Lignite	BT Coal Dir. Gasif.	Char	Char	BT Coal Mild Gasif.
Bed Material	Limestone	Sand	Limestone	Limestone	Sand	Char
Temperature (°F)	1370	1430	1390	1456	1467	1150
Feed Rate (lb/hr, as rec'd)	15.1	7.3	16.9	24.0	24.0	90.0
Steam Rate (lb/hr)	30.6	28.3	28.3	53.5	50.5	98.4
Steam/Feed Ratio	2.03	3.88	1.67	2.23	2.10	1.09
C Gasification Eff. (%)	96.1	95.7	85.9	90.6	88.0	N/A
H ₂ Yield (SCF/lb MAF Feed)	44.4	37.0	23.0	31.9	38.8	N/A
Dry Gas Composition (Vol. %)						
<u>Component</u>						
H ₂	69.38	62.27	55.60	53.32	56.93	33.48
CO ₂	21.46	26.47	28.35	23.67	23.95	23.22
CO	6.14	8.83	12.22	21.69	17.37	8.24
CH ₄	2.40	1.77	3.13	1.28	1.54	28.57
C ₂ H ₄	0.26	0.28	0.32	0.00	0.13	1.45
C ₂ H ₆	0.12	0.07	0.15	0.00	0.00	1.64
C ₃ H ₆	0.04	0.04	0.05	0.00	0.00	1.07
C ₃ H ₈	0.01	0.00	0.00	0.00	0.00	0.38
i-Butane	0.00	0.00	0.01	0.00	0.00	00.0
n-Butane	0.03	0.02	0.03	0.00	0.00	0.69
Pentane	0.00	0.00	0.00	0.00	0.00	0.32
Hexane	0.00	0.00	0.00	0.00	0.00	0.44
CH ₃ SH	0.00	0.00	0.00	0.00	0.00	0.06
COS	0.00	0.00	0.00	0.00	0.00	0.06
Toluene	0.00	0.00	0.00	0.00	0.00	0.19
H ₂ S	0.16	0.26	0.14	0.04	0.08	0.19
Total	100.00	100.00	100.00	100.00	100.00	100.00
Dry Gas (SCFM)	9.7	4.4	8.8	18.8	21.4	4.7
HHV (Btu/SCF)	279.2	258.3	263.2	256.5	259.6	570.3
Carbon (lb/hr)	5.6	3.1	7.4	16.7	17.4	7.2

* Nitrogen was used as fluidizing gas for mild gasification for char production.

TABLE 7. ANALYSIS FOR FEEDSTOCKS TESTED IN PULSE-ENHANCED INDIRECT GASIFIER

COMPOSITION (Vol.%)	PISTACHIO SHELLS	PISTACHIO SHELLS	WOOD CHIPS	RICE HULLS	RECYCLED MILL FIBER WASTE	RECYCLED WASTE PAPER W/PLASTIC	KRAFT MILL SLUDGE	RDF SAND BED	MSW SAND BED	MSW LIMESTONE BED
H ₂	37.86	35.04	48.11	42.83	38.86	50.50	52.94	45.54	55.21	54.40
CO	18.84	23.43	22.91	19.67	23.34	19.26	11.77	25.26	28.10	25.46
CO ₂	28.73	25.20	20.18	24.40	23.27	20.10	21.94	14.51	5.95	5.66
CH ₄	10.65	11.31	8.32	11.56	8.31	8.42	8.95	8.30	5.00	5.86
C ₂	<u>3.92</u>	<u>5.02</u>	<u>0.48</u>	<u>1.54</u>	<u>6.40</u>	<u>1.72</u>	<u>3.00</u>	<u>6.38</u>	<u>5.74</u>	<u>8.62</u>
TOTAL	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
HHV	370	406	329	367	412	364	372	418	374	448
TEMP. (°F)	1317	1216	1286	1326	1250	1326	1250	1450	1410	1306
YIELD (% Carbon)	94.1	92.1	93.0	N/A	86.8	N/A	56.0	83.6	93.7	83.8

TABLE 8. PRODUCT GAS COMPOSITIONS AND YIELDS FOR BIOMASS TESTS
CONDUCTED IN THE MTCI INDIRECTLY HEATED GASIFIER

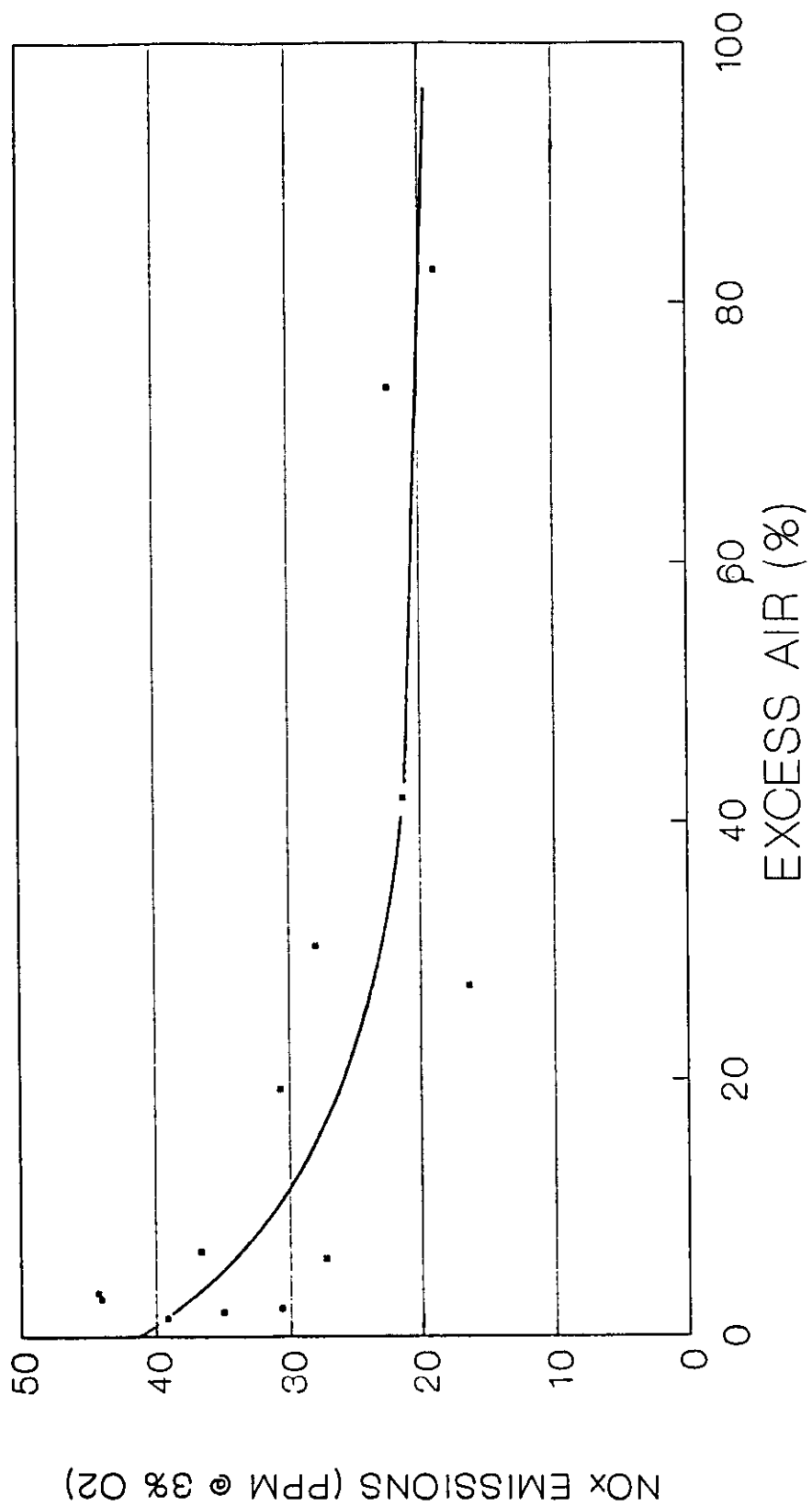


FIGURE 3. EFFECT OF STOICHIOMETRY ON NO_x EMISSIONS FROM A PULSE COMBUSTOR

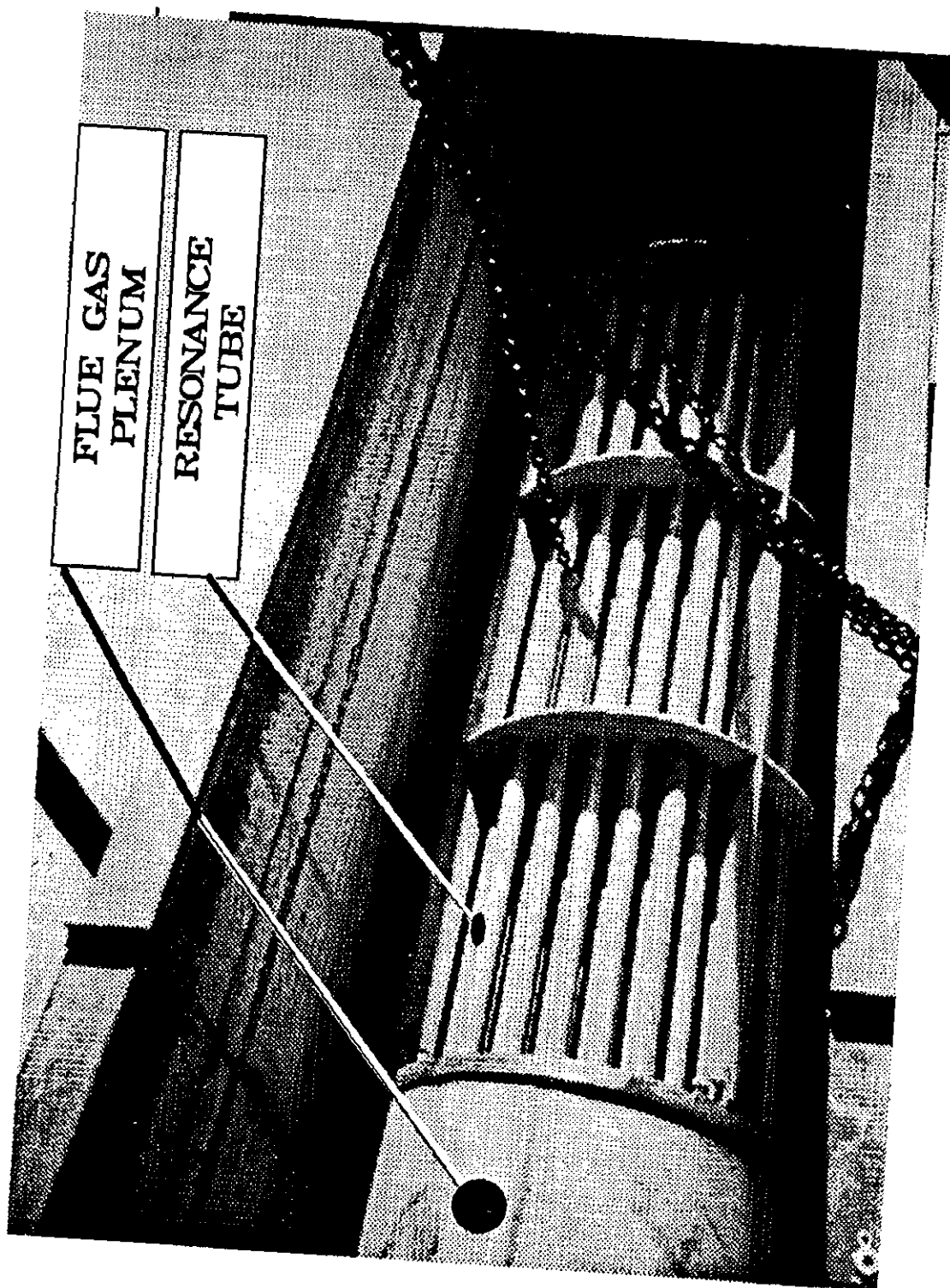


FIGURE 4. MULTIPLE RESONANCE TUBE PULSE COMBUSTOR

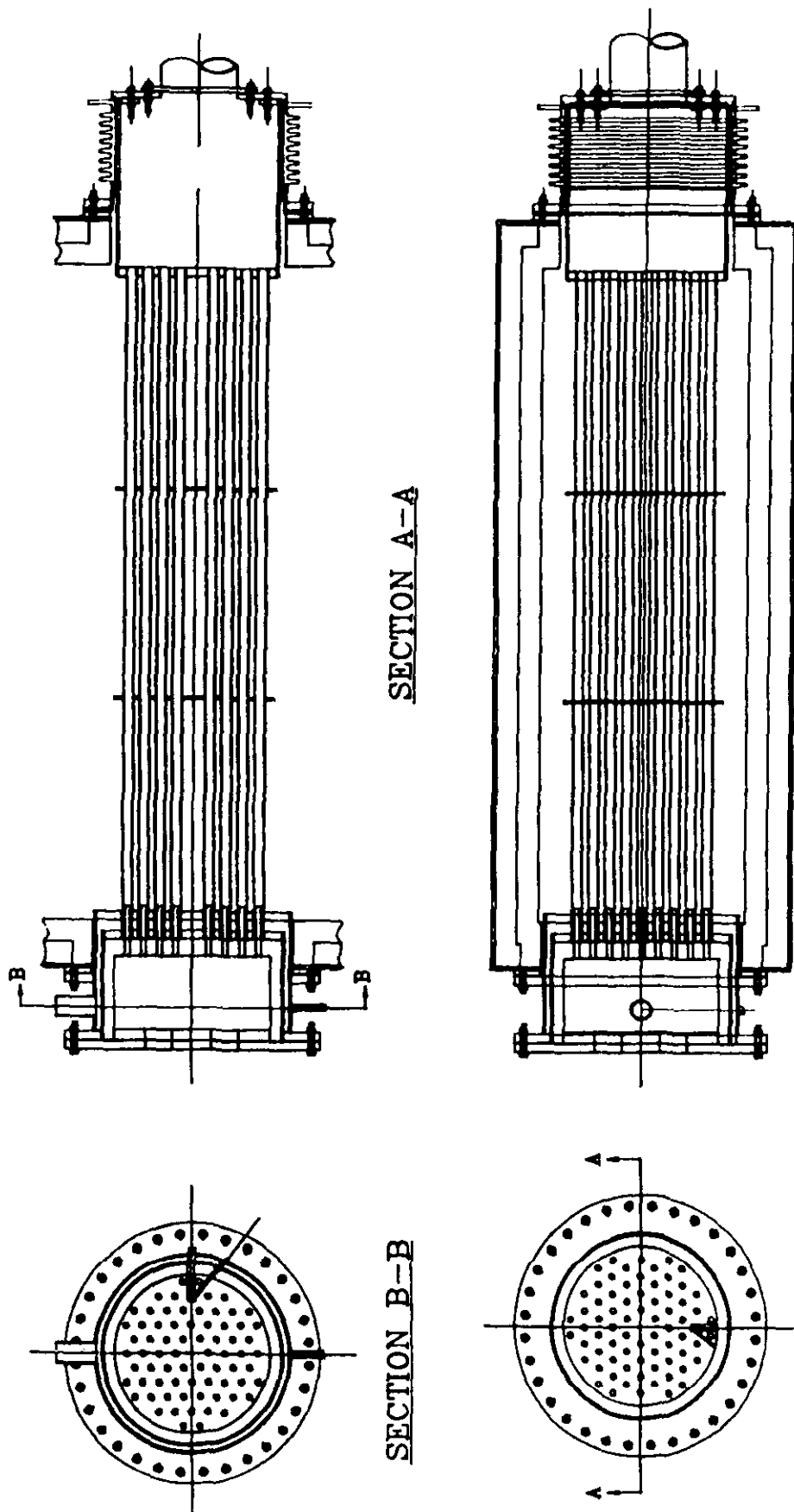


FIGURE 5. GASIFIER HEATER MODULE

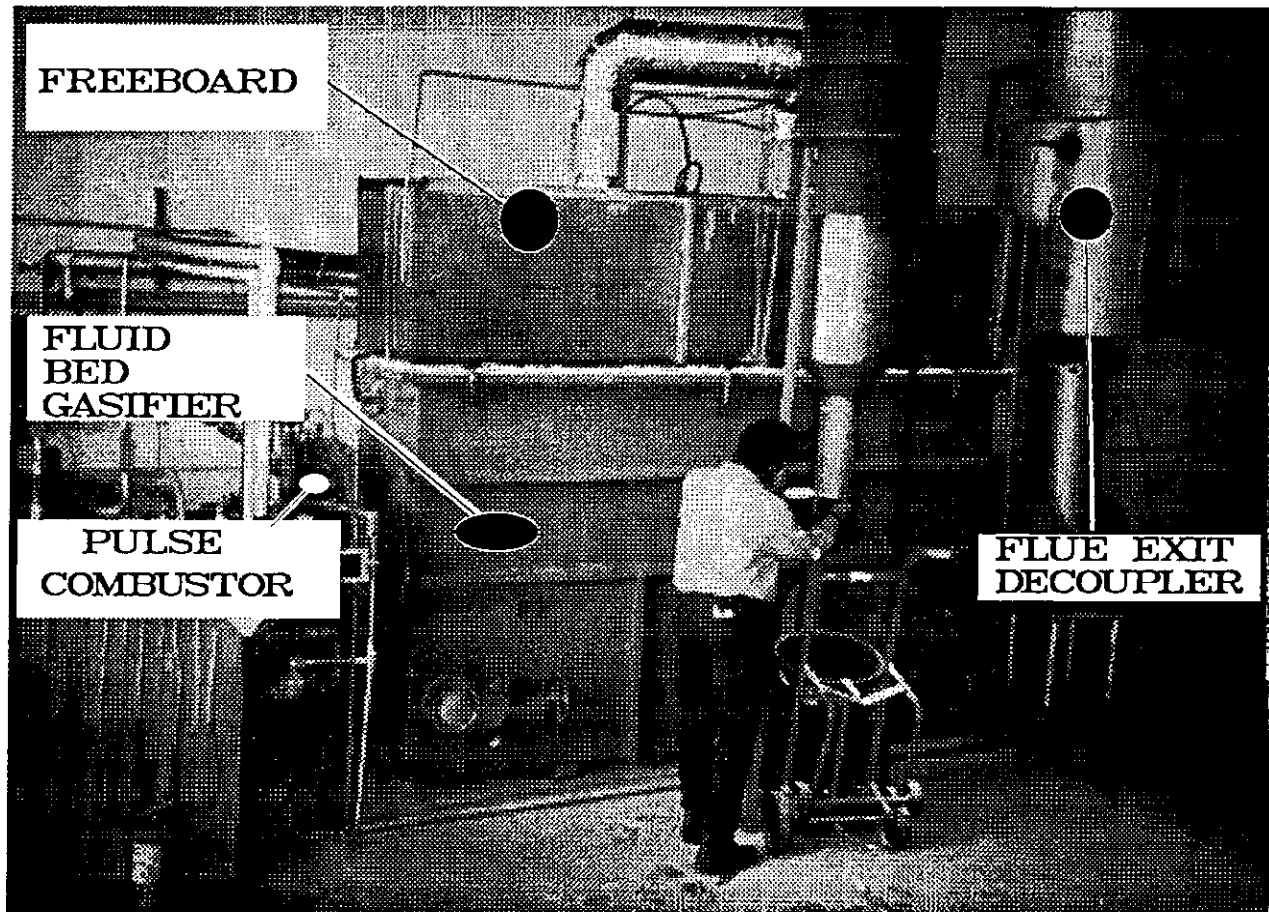


FIGURE 6. INDIRECTLY HEATED GASIFIER PILOT UNIT (12 tons day)

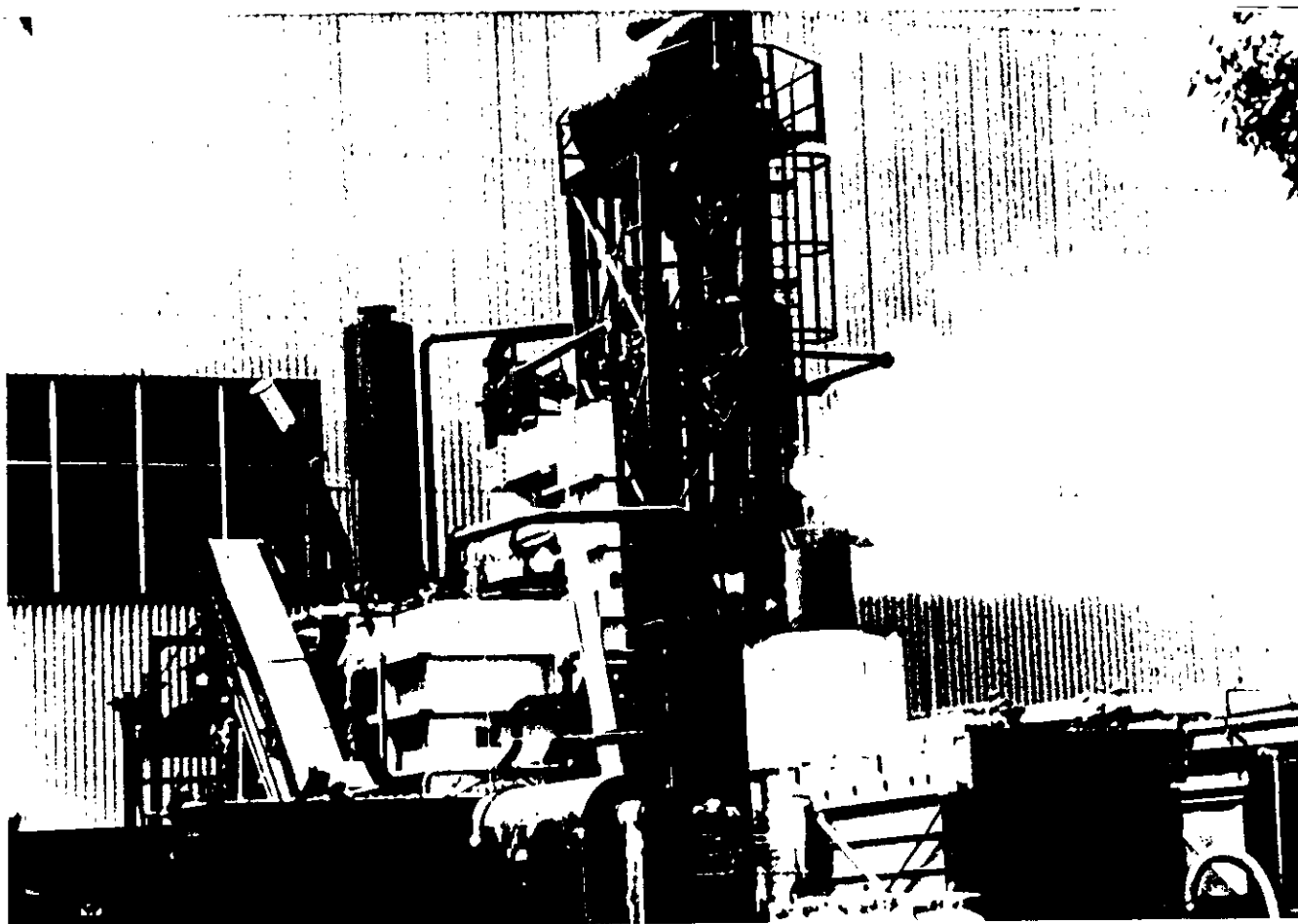


FIGURE 7. INLAND CONTAINER CORPORATION GASIFICATION UNIT (24 tons/day Gasifier)

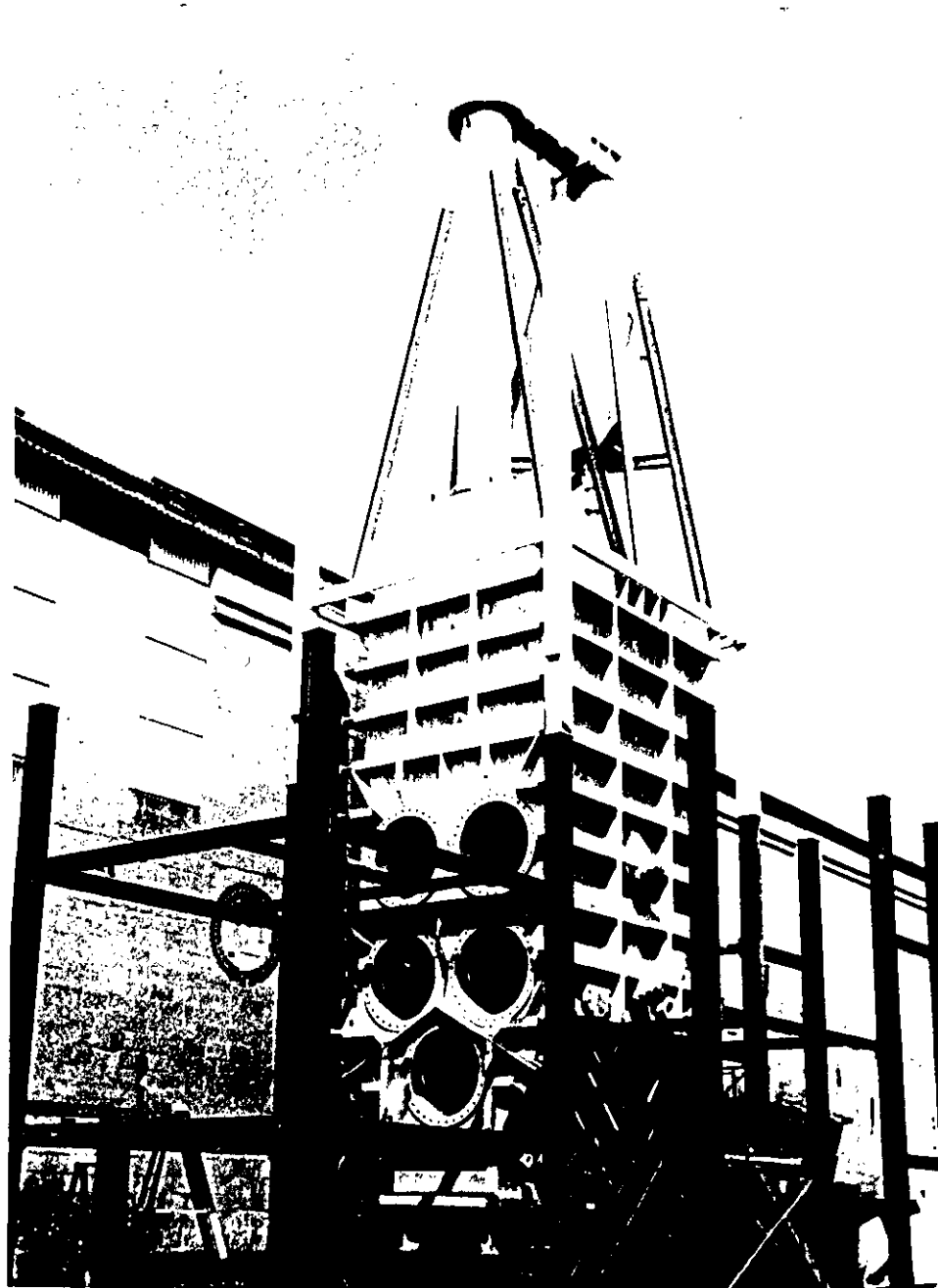
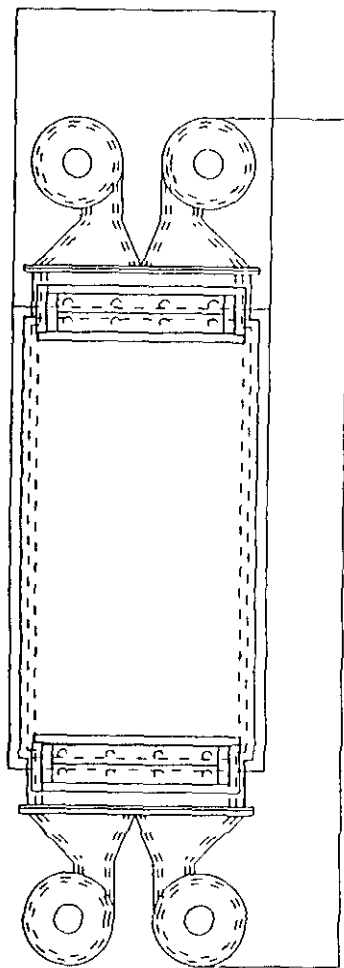


FIGURE 8. BLACK LIQUOR UNIT FOR WEYERHAEUSER



VESSEL CHARACTERISTICS.

Bed Size	27' x 10'
Freeboard Height	12'
Bed Depth	10'

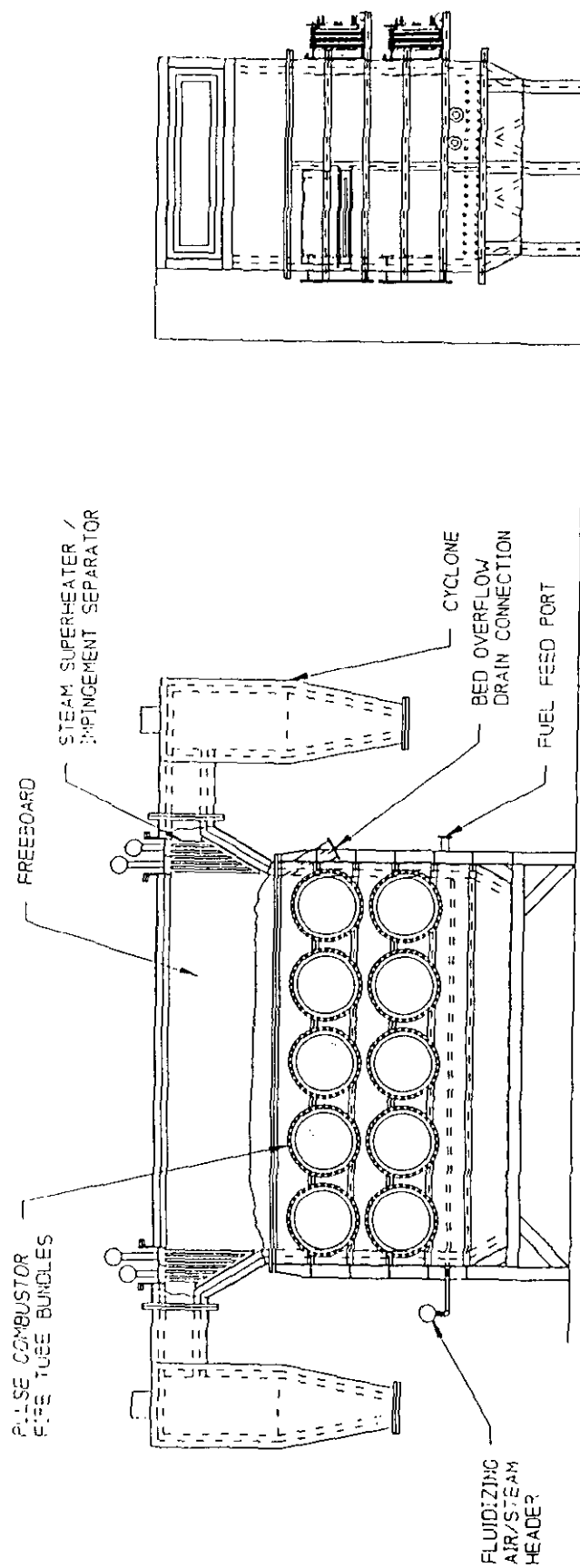


FIGURE 9. 300-TON PER DAY GASIFIER

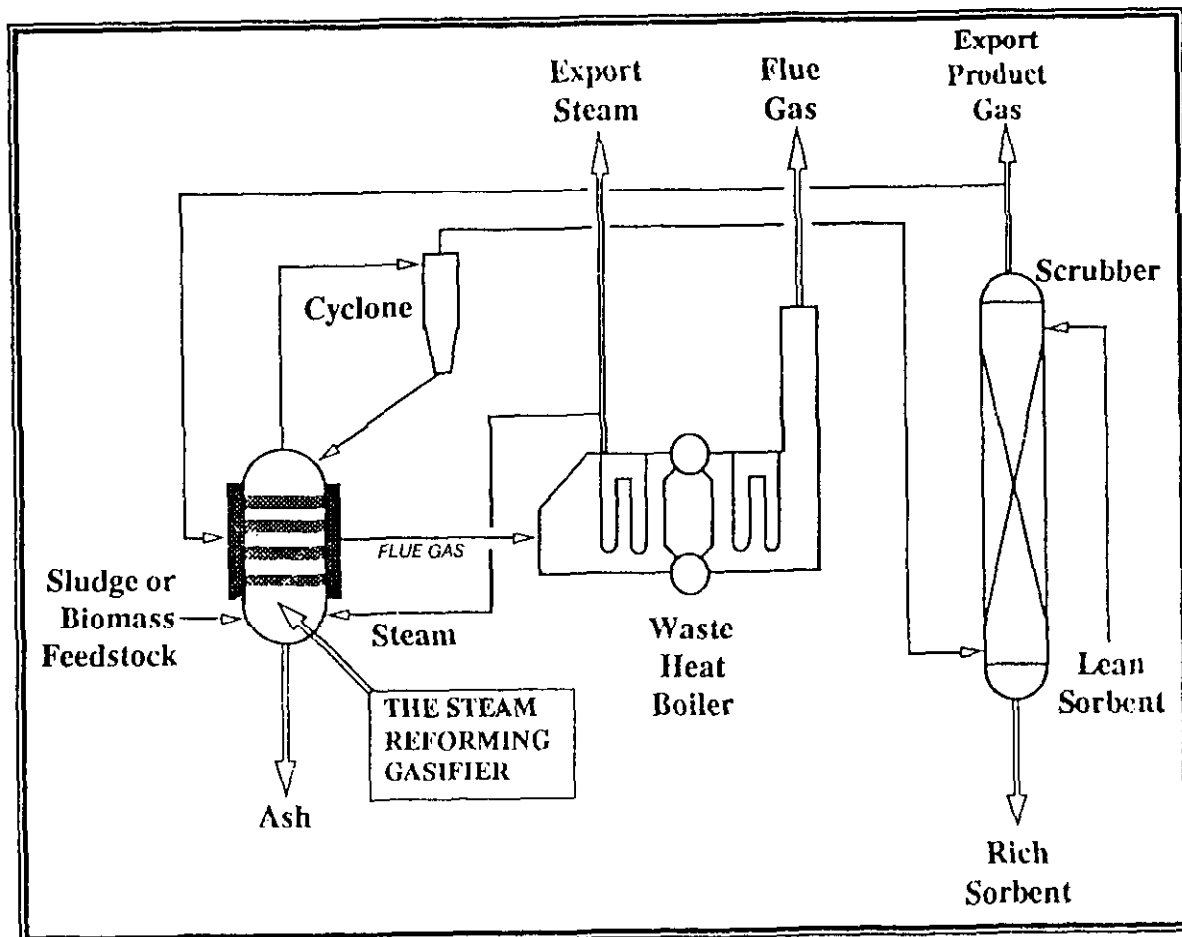


FIGURE 10. SIMPLIFIED SYSTEM SCHEMATIC

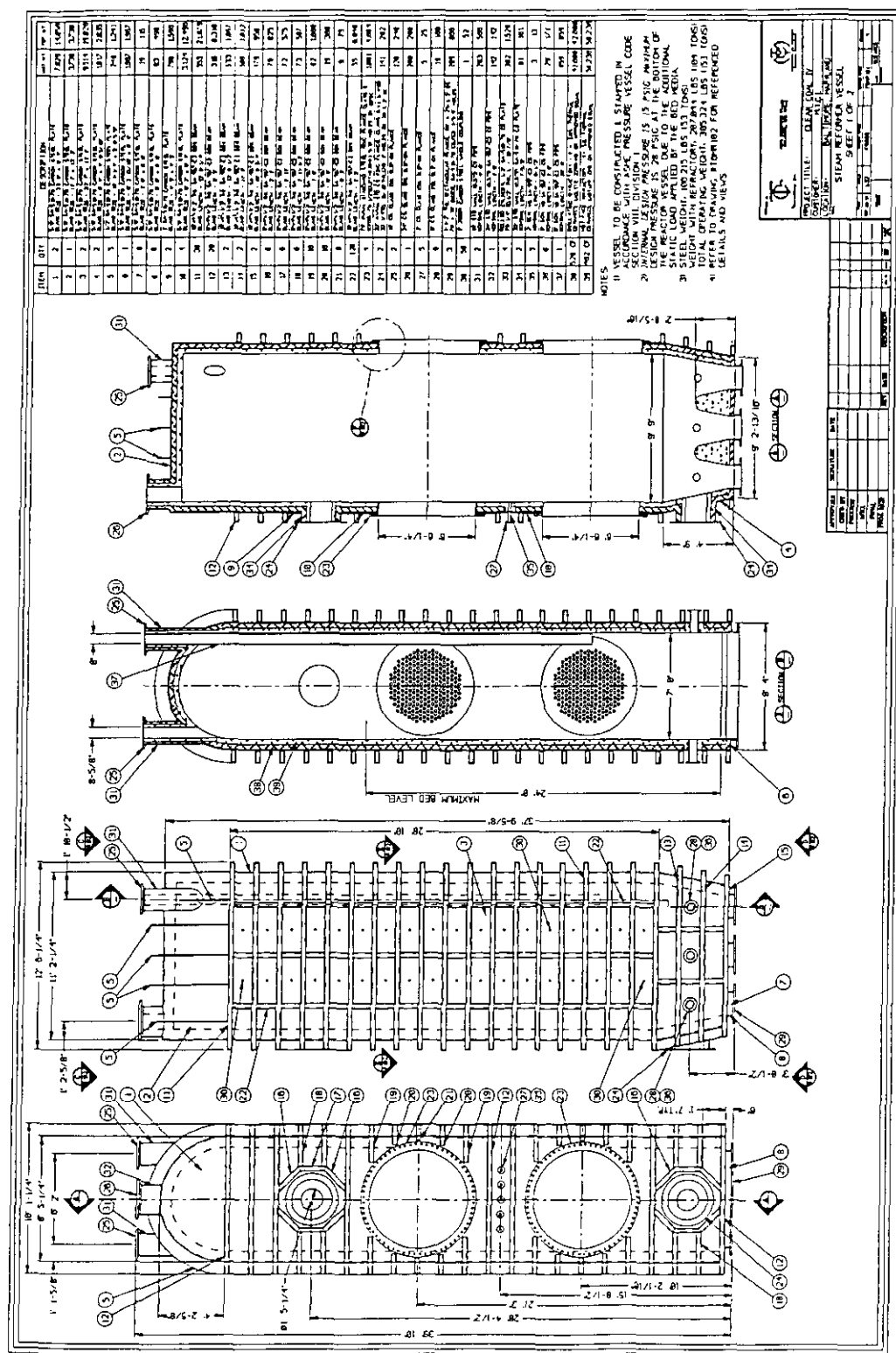


FIGURE 12. TEST VESSEL

BLAST FURNACE GRANULAR COAL INJECTION

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ABSTRACT

A blast furnace coal injection system is being constructed and will be tested on large high productivity blast furnaces at the Burns Harbor plant of the Bethlehem Steel Corporation. This project will demonstrate injection facilities on two blast furnaces and will permit operation with either granular (coarse) or pulverized (fine) coal injection. Injection rates up to 400 lbs/ton hot metal will be demonstrated with a variety of domestic coal types. The project is currently in the construction stage with mechanical completion expected by year-end 1994. The system is expected to be placed into formal operation during the second quarter of 1995.

INTRODUCTION

BACKGROUND - COAL INJECTION FOR BLAST FURNACES

The ironmaking blast furnace is at the heart of the integrated steelmaking process. As shown on Figure 1, prepared ferrous materials, along with coke, are charged alone or in combination with lump iron ore into the blast furnace. Preheated air is injected near the bottom of the furnace and the ferrous materials are reduced and melted by hot combustion products from the burning coke to produce molten iron. The molten iron is combined with scrap and flux and is refined in the steelmaking process. The basic oxygen furnace is the predominant method used in integrated steelmaking.

Figure 2 provides more detail on the blast furnace operation. Raw materials (ore, coke and limestone) are conveyed to the top of the furnace either on a conveyor belt or in a "skip" car. All or part of the limestone (and dolomite) which is used as flux to remove contaminants in the coke and ore, can be charged directly or combined in the ferrous sinter and pellet feed during their production.

The raw materials are charged to the top of the furnace through a lock hopper arrangement to prevent the escape of pressurized hot reducing gases. Air needed for the combustion of coke to generate the heat and reducing gases for the process is passed through stoves and heated to 1500-2300°F. The heated air (hot blast) is conveyed to a refractory-lined bustle pipe located around the perimeter of the furnace. The hot blast then enters the furnace through a series of ports (tuyeres) around and near the base of the furnace. The molten iron and slag are discharged through openings (tapholes) located below the tuyeres. Resultant molten iron flows to refractory-lined ladles for transport to the steelmaking shop.

A schematic showing the various zones inside the blast furnace is given on Figure 3. As can be seen, the raw materials, which are charged to the furnace in batches, create discrete layers of ore and coke. As the hot blast reacts with and consumes coke at the tuyere zone, the burden descends in the furnace resulting in a molten pool of iron flowing around unburned coke at the furnace bottom (bosh area). Reduction of the descending ore occurs by reaction with the rising hot reducing gas that is formed when coke is burned at the tuyeres.

The cohesive zone directly above the tuyeres is so called because it is in this area that the ore, which has been reduced is being melted and passes through layers of unburned coke. The coke layers provide the permeability needed for the hot gases to pass through this zone to the upper portion of the furnace. Unlike coal, coke has the qualities needed to retain its integrity in this region and is the reason that blast furnaces cannot be operated without coke in the burden.

The hot gas leaving the top of the furnace is cooled and cleaned. Since it has a significant heating value (80-100 BTU/scf), it is used to fire the hot blast stoves. The excess is used to generate steam and power and for other uses within the plant.

Over the years many injectants (natural gas, tar, oils, etc.) have been used in blast furnaces to reduce the amount of coke used. Their use is a matter of economics with each location making choices considering the site specific relative costs of coke and injectants available. Natural gas has been a common injectant used in this country. Technological developments in Europe and Asia, where coal has been widely used as an injectant, have established that the highest levels of injection and subsequent displacement of coke can be obtained by using coal.

A major consideration in evaluating coal injection in the United States is the aging capacity of existing cokemaking facilities and the high capital cost to rebuild these facilities to meet emission guidelines under the Clean Air Act Amendments. The increasingly stringent environmental regulations and the continuing decline in domestic cokemaking capability will cause significant reductions in the availability of commercial coke over the coming years. Due to this decline in availability and increase in operating and maintenance costs for domestic cokemaking facilities, commercial coke prices are projected to increase by more than general inflation. Higher levels of injectants, such as coal, enable domestic integrated steel producers to minimize their dependence on coke.

COAL PREPARATION AND INJECTION AT BURNS HARBOR

Natural gas is the injectant currently being used in the production of iron in the Burns Harbor blast furnaces of Bethlehem Steel Corporation. Even with maximum use of natural gas, the plant lacks sufficient cokemaking capability to support its ironmaking capability. That situation led Bethlehem to the decision to submit a proposal to the DOE to conduct a comprehensive assessment of coal injection in the Burns Harbor blast furnaces. The program is designed to provide the industry with comparative data on a variety of U.S. coal types, grind sizes, etc. Following an extensive review by the DOE, Bethlehem's Blast Furnace Granular Coal Injection System Demonstration Project was one of thirteen demonstration projects accepted for funding in the Clean Coal Technology Program third round of competition.

The DOE financial assistance will enable Bethlehem to demonstrate granular coal injection using a technology successfully employed by British Steel plc. Under the terms of the DOE financial assistance, Bethlehem will demonstrate granular coal injection at rates of up to 400 pounds per net ton of hot metal for a number of domestic coals. Also, as part of the Cooperative Agreement, Bethlehem will share the results of coal evaluations and comprehensive system performance with other domestic steel companies.

PROJECT GOALS

As shown on Figure 4, this project will obtain comparative data for a variety of coal types, grinds and injection level. The primary thrust of the work is to demonstrate (a) conversion for, (b) optimization of and (c) commercial performance characteristics of granular coal as a supplemental fuel for steel industry blast furnaces. The technology will be demonstrated on large, hard-driven blast furnaces using a wide range of coal types available in the U.S. The planned tests will assess the impact of coal particle size distribution as well as chemistry on the amount of coal that can be injected effectively. Upon successful completion of the work, the results will provide to others the information and confidence needed to assess the technical and economic advantages of applying the technology to their own facilities.

TECHNOLOGY DESCRIPTION

Bethlehem decided to utilize the Simon Macawber Blast Furnace Granular Coal Injection (BFGCI) System, which, unlike systems more widely employed that utilize only pulverized coal, is capable of injecting both granular and pulverized coal. Bethlehem believes that the Simon Macawber system offers a variety of technical and economic advantages which make this system potentially very attractive for application in the U.S. basic steel industry. A schematic showing the application of the technology to the blast furnace is given on Figure 5. Some of the advantages of this technology, which is being marketed in North America by ATSI/Simon Macawber include:

- The injection system has been used overseas with granular coal as well as with pulverized coal. No other system has been utilized over this range of coal sizes.
- The potential costs for granular coal systems are less than for pulverized.
- Granular coal is easier to handle in pneumatic conveying systems. Granular coals are not as likely to stick to conveying pipes if moisture control is not adequately maintained.
- Research tests conducted by British Steel indicate that granular coal is more easily maintained in the blast furnace raceway (combustion zone) and is less likely to pass through the coke bed. Coke replacement ratios obtained by British Steel have not been bettered in any worldwide installation.
- Granular coal's coarseness delays gas evolution and temperature rise associated with coal combustion in the raceway. Consequently, it is less likely to generate high temperatures and gas flows at the furnace walls which result in high heat losses, more rapid refractory wear and poorer utilization of reducing gases.
- System availability has exceeded 99 percent during several years of operation at British Steel.
- High injection levels require accurate variable control of injection rates, both for individual tuyeres and the complete system. The unique variable speed, positive displacement Simon-Macawber injectors provide superior flow control and measurement over other coal injection systems.

HISTORY OF THE TECHNOLOGY

Coal injection into blast furnaces dates back more than 100 years; it was the first fuel known to have been injected. In the United States, pulverized coal has been injected into blast furnaces at the Ashland Kentucky Plant of Armco Steel since the mid-1960's. However, different economic situations at other facilities in the United States precluded wide application of coal injection technology. That situation has changed and a number of steel companies in the U.S. have installed or are planning to install coal injection facilities.

As with other companies, Bethlehem Steel has monitored the progress of blast furnace coal injection developments worldwide for a number of years. The development and application of a process that permits the use of granular (as well as pulverized) coal caught our interest. The equipment provides the capability of using either grind size, with the option of long-term use of the less expensive granular type.

The joint development by British Steel and Simon-Macawber of a process for the injection of granular coal into blast furnaces began in 1982 on the Queen Mary Blast Furnace at the Scunthorpe Works. (1,2) The objective of the development work was to inject granular coal into the furnace and test the performance of the Simon-Macawber equipment with a wide range of coal sizes and specifications. Based on Queen Mary's performance, coal injection systems were installed on Scunthorpe's Queen Victoria, Queen Anne and Queen Bess (operational standby) blast furnaces and on Blast Furnaces 1 and 2 of the Ravenscraig Works. Queen Victoria's system was brought on line in November, 1984 and Queen Anne's in January, 1985. The Ravenscraig systems were started up in 1988. The success of the GCI systems at Scunthorpe and Ravenscraig, although demonstrated on smaller blast furnaces, led Bethlehem to conclude that the system could be applied successfully to large blast furnaces using domestic coals.

INSTALLATION DESCRIPTION

The coal preparation/injection facility is being retrofitted to blast furnaces, Units "C" and "D", at our Burns Harbor plant located in Porter County, Indiana, on the southeast shore of Lake Michigan. Highlights of the blast furnace and coal injection facilities are given on Figure 6. As noted on this Figure, Burns Harbor has experience with the injection of tar and oil as well as natural gas. This experience will be an asset when the coal injection trials begin.

A simplified flow diagram for the process is shown on Figure 7. The Raw Coal Handling Equipment and the Coal Preparation Facility includes the facilities and equipment utilized for the transportation and preparation of the coal from an existing railroad car dumper until it is prepared and stored prior to passage into the Coal Injection Facility; the Coal Injection Facility accepts the prepared coal and conveys it to the blast furnace tuyeres.

SITE LOCATION

The Coal Preparation Facility, the Coal Injection Facility and a utilities and control center for the facilities will be located in the process building and attached utilities building. The buildings are located between the two blast furnaces on a site previously occupied by a blast furnace warehouse and maintenance building. This location was chosen because it is the closest equidistant site to the two blast furnaces. Such location will minimize pressure drop and power requirements for transporting the coal to the blast furnaces.

RAW COAL HANDLING EQUIPMENT

Raw Coal Handling. Coal for this project will be transported by rail from coal mines to Burns Harbor similar to the way in which the plant now receives coal shipments for the coke ovens. The coal will be unloaded using an existing railroad car dumper, which is currently part of the blast furnace material handling system. A modification to the current conveyor will be made to enable the coal to reach either the coke ovens or the coal pile for use at the Coal Preparation Facility.

This modification will require a new 60-inch wide transfer conveyor to be installed from the existing conveyor and run east about 186 feet (40 feet above the ground) to a junction house. There the coal will be transferred to a new 60-inch wide stockpile conveyor which will run 760 feet to the north and end at the space for the new raw coal storage pile. The coal pile will be formed using a 200-ft. long radial stacker capable of building a 10-day storage pile (approximately 28,000 tons). The new material handling system from the car dumper to the coal storage pile will be sized at 2,300 tons per hour to match the output of the car dumper.

Raw Coal Reclaim. The raw coal reclaim tunnel will be installed underground beneath the coal storage pile. The concrete tunnel will be about 12 feet wide and 16 feet high and will contain four reclaim hoppers in the top of the tunnel. The reclaim hoppers, which are directly beneath the coal pile, will feed a 36-inch wide conveyor in the tunnel. The 400-ft. long reclaim conveyor will transport the coal at a rate of 400 tons per hour above ground to the south of the storage pile. A magnetic separator will be located at the tail end of the conveyor to remove tramp ferrous metals. The conveyor will discharge the coal onto a vibrating screen which will separate coal over 2 inches in size from the main stream of minus 2-inch coal. The oversized coal will vary depending on the weather (more during the winter when frozen lumps are expected) and will pass through a precrusher which will discharge minus 2-inch coal. The coal from the precrusher will join the coal that passed through the screen and will be conveyed from ground level by a 36-inch wide plant feed conveyor to the top of the building that houses the Coal Preparation Facility.

The reclaiming of coal from the pile will be done by gravity as long as there is coal above each of the reclaim hoppers. It will be necessary to have a bulldozer on the pile to periodically push coal from the "dead" storage areas to the "live" storage areas above each of the reclaim hoppers.

COAL PREPARATION FACILITY

The plant feed conveyor will terminate about 103 feet high at the top of the process building that houses the Coal Preparation Facility. Coal will be transferred to a distribution conveyor, which will enable the coal to be discharged into either of two steel raw coal storage silos. The raw coal silos will be cylindrical in shape with conical-shaped bottoms. They will be completely enclosed with a vent filter on top. Each silo will hold 240 tons of coal, which is a four-hour capacity at maximum injection levels. Air cannons will be located in the conical section to loosen the coal to assure that mass flow is attained through the silo.

Coal from each raw coal silo will flow into a feeder which controls the flow of coal to the coal preparation mill. In the preparation mill the coal will be ground to the desired particle size. Products of combustion from a natural gas fired burner will be mixed with recycled air from the downstream side of the process and will be swept through the mill grinding chamber. The air will lift the ground coal from the mill vertically through a classifier where oversized particles will be circulated back to the mill for further grinding. The proper sized particles will be carried away from the mill in a 52-inch pipe. During this transport phase, the coal will be dried to 1-1.5% moisture. The drying gas will be controlled to maintain oxygen levels below combustible levels. There will be two grinding mill systems. Each system will produce 30 tons per hour of pulverized coal or 60 tons per hour of granular coal.

The prepared coal will then be screened to remove any remaining oversize material. Below the screens, screw feeders will transport the product coal into one of four 180-ton product storage silos and will then be fed into a weigh hopper in two-ton batches. The two ton batches will be dumped from the weigh hopper into the distribution bins which are part of the Coal Injection Facility.

COAL INJECTION FACILITY

The Coal Injection Facility will include four distribution bins located under the weigh hoppers described above. Each distribution bin contains 14 conical-shaped pant legs. Each pant leg will feed an injector which allows small amounts of coal to pass continually to an injection line. Inside the injection line, the coal will be mixed with high-pressure air and will be carried through approximately 600 feet of 1-1/2-inch pipe to an injection lance mounted on one of the 28 tuyere blowpipes at each furnace. At the injection lance tip, the coal will be mixed with the hot blast and will be carried into the furnace raceway. The fourteen injectors at the bottom of the distribution bin will feed alternate furnace tuyeres.

Each furnace requires two parallel series of equipment, each containing one product coal silo, one weigh hopper, one distribution bin, 14 injectors, 14 injection lines and 14 injection lances.

TEST PLAN

The project will address a broad range of technical/economic issues as shown on Figure 8.

COAL GRIND SIZE

The facility has the potential to evaluate coal injection over a broader range of coal particle sizes than has ever been conducted at any plant in the U.S. Previously, only pulverized coal, defined as 70-80% minus 200 mesh (74 microns), has been injected commercially in the U.S. The primary focus of this project will be on granular coal, defined as 100% minus 4 mesh (5 mm), 98% minus 7 mesh (3 mm) and less than 30% minus 200 mesh (74 microns). The work will demonstrate on a commercial scale in the U.S. a system that can inject either granular or pulverized coal. More important, it will show the effects of injected domestic coal types on blast furnace performance. If the successful experiences of European operations with granular coal can be repeated or improved upon in the CCT III Project, then the advantages of granular coal over pulverized coal injection systems for commercial applications in the U.S. will have been demonstrated. These potential advantages include reduced capital cost for the grinding facilities and reduced consumption of electric energy (and other operating cost factors) for grinding the coal. The data to be generated will be of value in the planning of future U.S. commercial installations.

COAL INJECTION RATE

Operation over a range of coal rates will be evaluated by this project. Bethlehem has targeted an injection level of 400 lbs of granular coal/NTHM. By operating and evaluating a range of injection rates, we will determine the technical limits for the coal injection system, establish the relationship between coal injection rate, furnace wall heat load, and any excessive wear of refractory lining to blast furnaces such as those at Burns Harbor; and confirm the operating costs and economic advantages that have been projected for granular coal injection.

COAL SOURCE

The Burns Harbor project will generate comparative data on coals with distinctly different chemical and physical characteristics. Plans call for using an Eastern bituminous coal with low ash and sulfur content; an Eastern bituminous coal with moderate ash and higher sulfur content; a Midwestern bituminous coal with higher inherent moisture but with low ash and moderate-to-high sulfur content; and a Western sub-bituminous coal with high inherent moisture but with low ash and sulfur content.

Each coal will be utilized for a sufficiently long period of time to assess how it performs as a blast furnace injectant. Coal handling and blast furnace parameters such as production, coke replacement, hot metal chemistry and slag volume are anticipated to be affected by the physical and chemical properties of the coal used for blast furnace coal injection. Data derived from this evaluation will make it possible for blast furnace operators to determine for themselves which coal would be most attractive for injection in their specific cases, including raw coal costs, transportation costs, coal grinding and injection costs, and the effects on blast furnace operations.

BLAST FURNACE CONVERSION METHOD

Neither of the two blast furnaces at Burns Harbor is equipped with coal injection facilities. In this project, both blast furnaces are being converted for coal injection. "C" Furnace will be fitted for coal injection during the current reline outage which should conclude in mid November, 1994. We propose to make the coal injection changes for "D" Furnace "on-the-fly", during very brief, monthly furnace outages. Thus, we will demonstrate the successful implementation of the modifications for blast furnace coal injection during both out-of-service and in-service modes. These will include planning and facilities for coal storage and handling, grinding, injection and alterations in the vicinity of the blast furnace itself (including work at the tuyeres).

Many of the physical components utilized in the coal injection system are also utilized in other commercial systems. The major portion of the technology envelope for this system is the integration of this equipment into a system that prepares coal as required for injection, allows flow to be controlled individually for each injection point into the blast furnace or allows all to be varied simultaneously, monitors the total amount injected and the flow to each tuyere, and includes the necessary know-how for injecting solid, granular fuel into a blast furnace. Key elements in this technology package are the weigh system, the variable flow injectors, lance sizing and positioning, and knowledge of how the factors of coal size, coal source and coal injection rate interact. Key elements of the portion of the project that pertain to blast furnace conversion methods involve the integration and coordination of engineering, construction and operations functions.

PROJECT SCOPE

To achieve these objectives, the demonstration project is divided into the three Phases.

- | | | |
|-----------|---|--------------|
| Phase I | - | Design |
| Phase II | - | Construction |
| Phase III | - | Operation |

The Project Schedule, Project Milestone Schedule and current Project Summary Cost Estimate are shown on Figures 9 through 11.

At the present time, Fluor Daniel is constructing the coal preparation and injection facility under a turnkey contract; the injection system is being supplied by ATSI/Simon Macawber (Figure 12). Regarding blast furnace improvements, those upgrades scheduled for the D furnace were completed during the last reline in late 1991. Planned major improvements to the C furnace will be completed during the current reline of that furnace. The coal injection system is scheduled to be completed by year-end with testing to begin shortly thereafter.

REFERENCES

1. D. S. Gathergood, "Coal Injection Into the Blast Furnace", International Iron & Steel Institute Committee on Technology, April 26, 1988.
2. D. S. Gathergood and G. Cooper, "Blast Furnace Injection - Why Granular Coal"? Steel Technology International, 1988.
3. D. Kwasnoski and L. L. Walter, "Blast Furnace Granular Coal Injection", Second Annual Clean Coal Technology Conference, Atlanta, GA, September 8, 1993.

FIGURE 1
THE STEELMAKING PROCESS

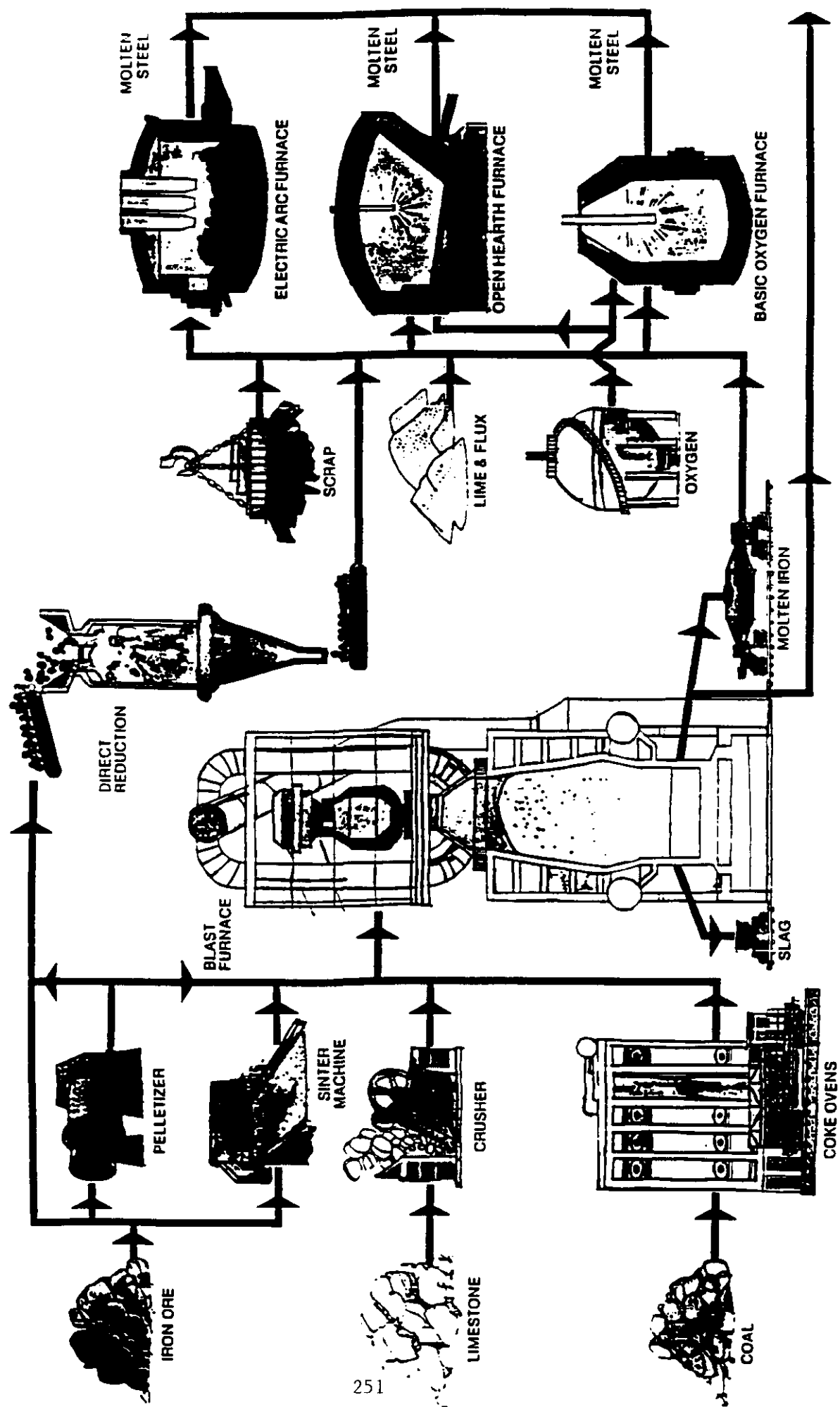


FIGURE 3
ZONES IN THE BLAST FURNACE

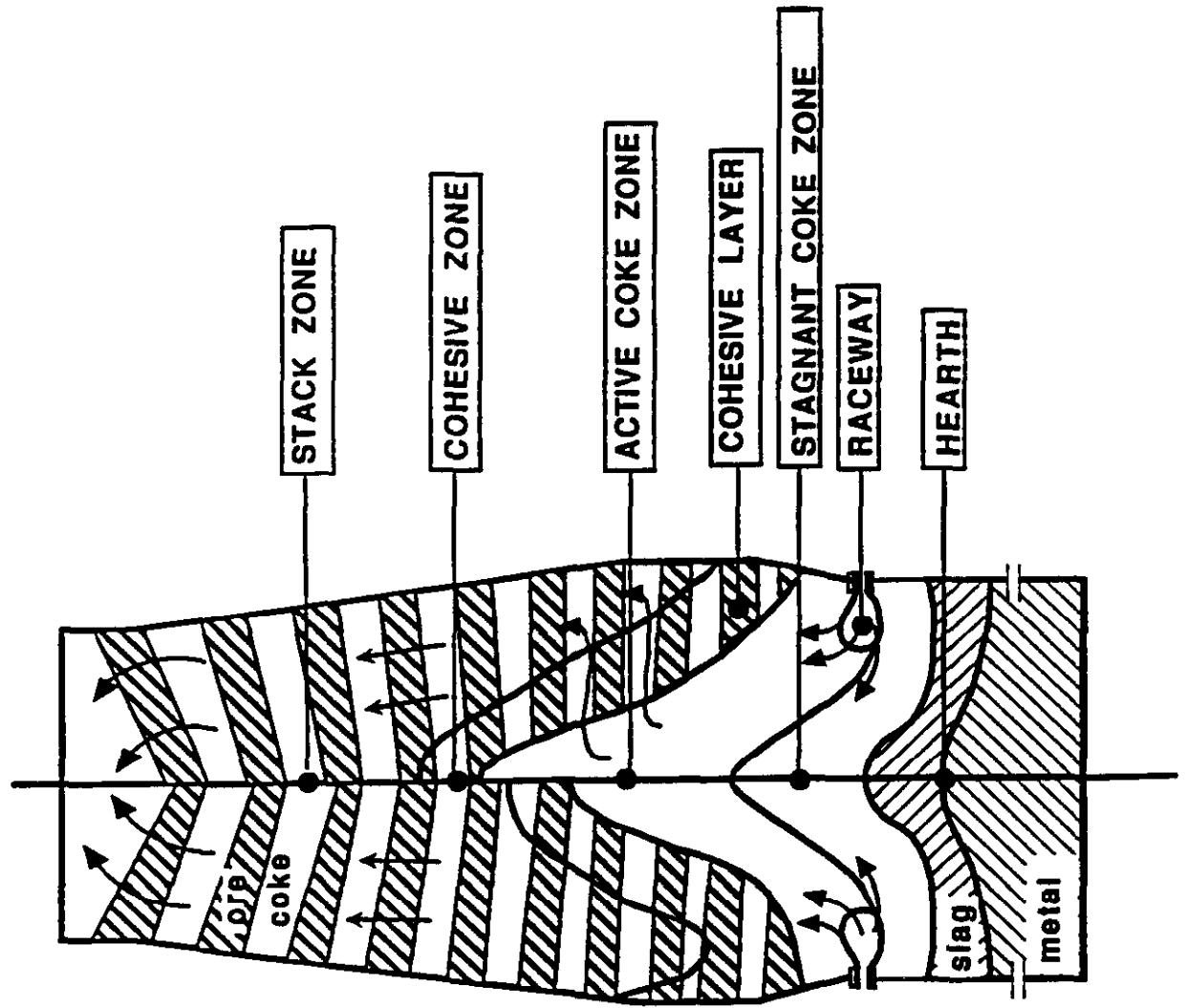


FIGURE 4

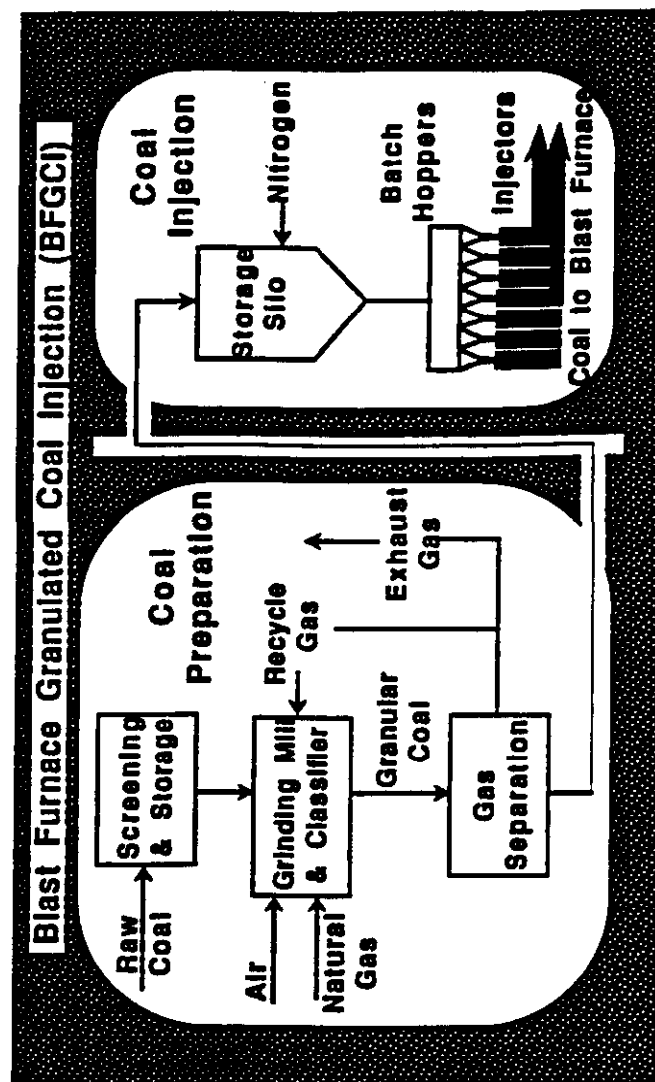
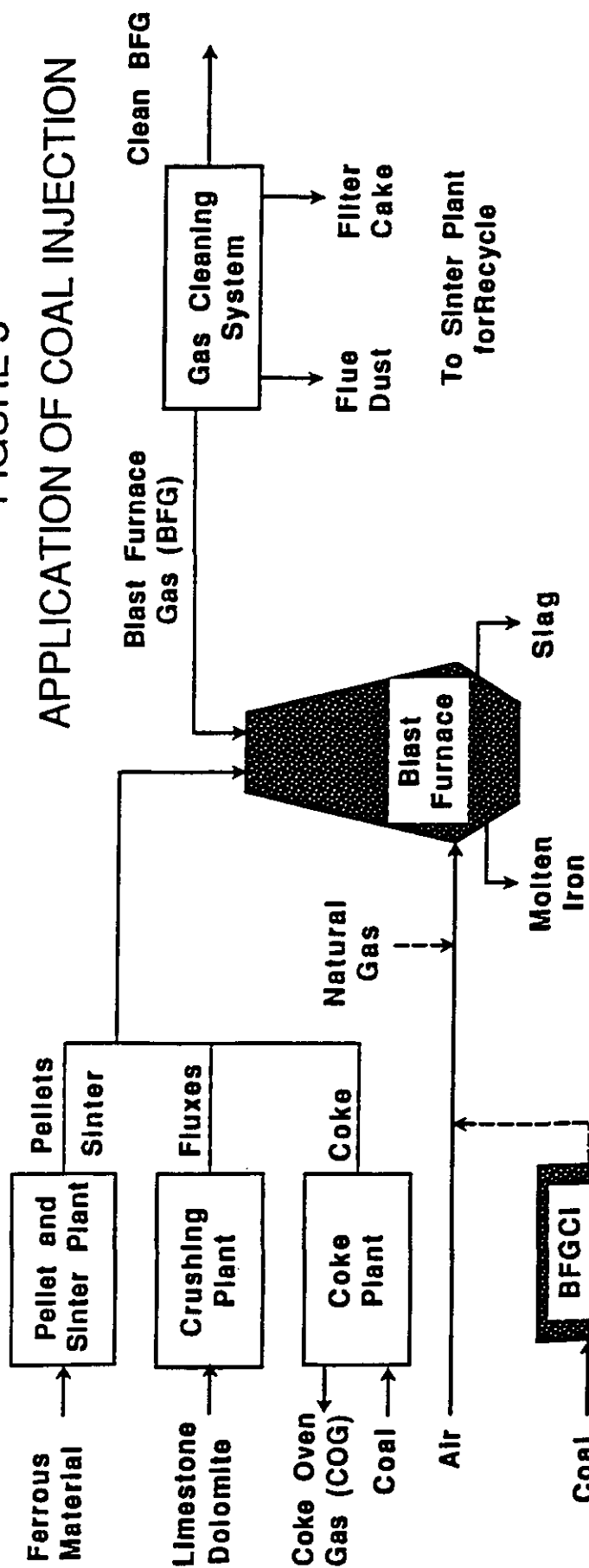
Coal Injection Test Program Parameters

Coal Grind Size	-	Granular (100% -4 mesh) to Pulverized (75% -200 mesh)
Injection Level	-	Up to 400 lbs per NTHM
Coal Types	-	East, Midwest and West (Differing Chemical and Physical Characteristics)
System Installation	-	During Furnace Reline and "On-the-Fly"
Reduced Coke Requirement	-	Less Reliance on Foreign Coke and/or Environmental Problems Associated with Domestic Coke Production

Bethlehem Steel Corp.

FIGURE 5

APPLICATION OF COAL INJECTION



<div> <div>FIGURE 6</div> <div>Coal Injection Test Site/Facilities</div> </div>	
Location	- Bethlehem Steel Burns Harbor Plant, Porter County, Northern Indiana
Blast Furnaces	
- Number	- 2
- Size	- 35 & 38 ft. Hearth Diameter
- Production Rate	- Approximately 7,000 tons/Day Pig Iron/Furnace (8 TPD per 100 cu.ft. Working Volume)
- Fuel Injection	- Natural Gas, Oil, Tar
Coal Injection Facilities	- Simon-Macawber
Bethlehem Steel Corp.	

FIGURE 7

COAL INJECTION - BURNS HARBOR PLANT

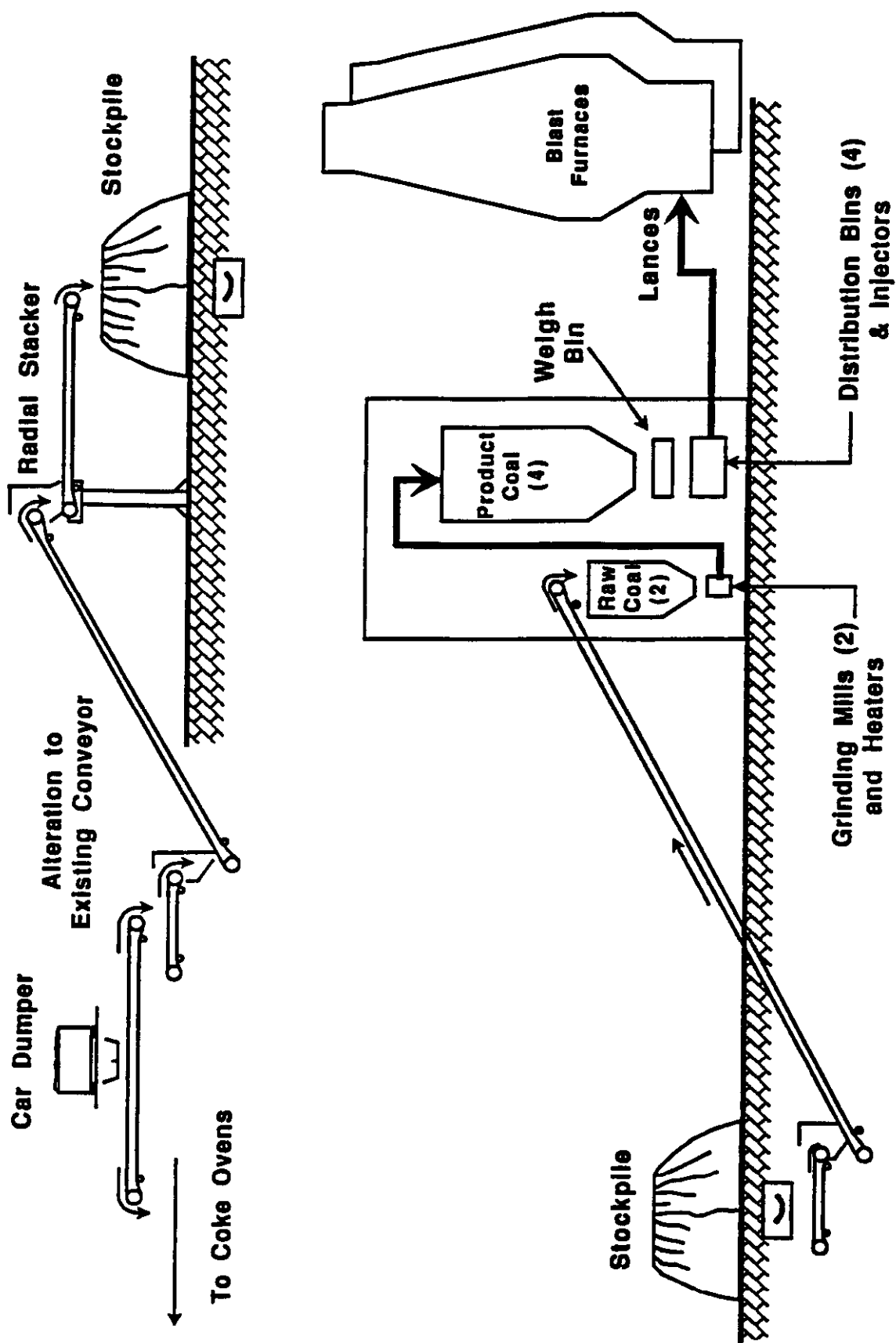


FIGURE 8

Coal Injection Test Program Goals

- | | |
|----------------------------|--|
| Coal Grind Size | - Granular (100% -4 mesh) to Pulverized (75% -200 mesh) |
| Injection Level | - Up to 400 lbs per NTHM |
| Coal Types | - East, Midwest and West (Differing Chemical and Physical Characteristics) |
| System Installation | - During Furnace Reline and "On-the-Fly" |

Bethlehem Steel Corp.

FIGURE 9
PROJECT SCHEDULE

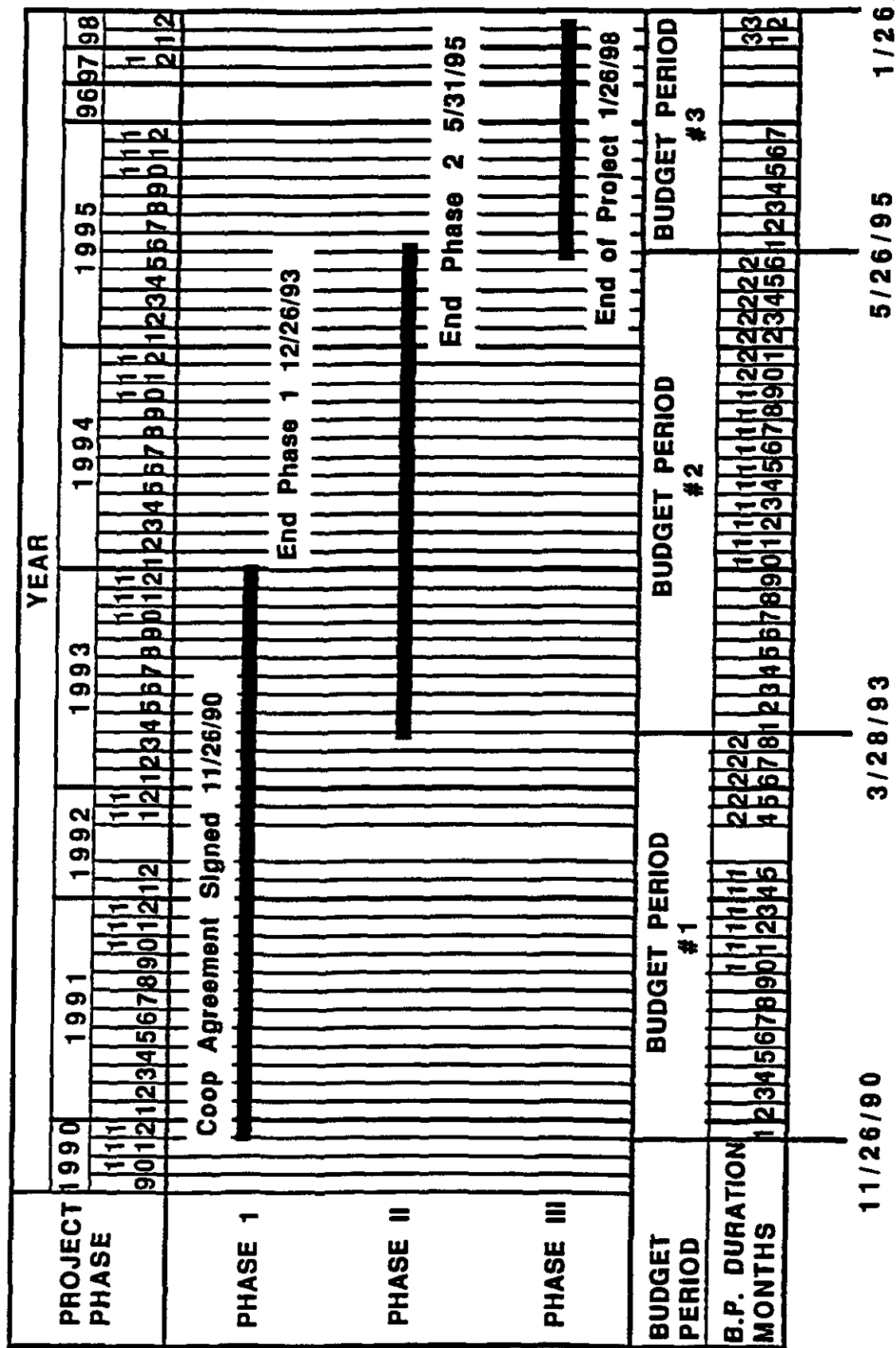


FIGURE 10

PROJECT MILESTONE SCHEDULE

Begin Detailed Construction Engineering	April 1, 1993
Received State Environmental Construction Permit	August 4, 1993
Start Construction	August 31, 1993
90% Design Review	January 12, 1994
50% Construction Review	June 1994
100% Construction Review	December 1994
Begin Coal Testing Demonstration	May 1995
Complete Coal Testing Demonstration	January 1998

FIGURE 11

PROJECT SUMMARY COST ESTIMATE

The estimated project cost is summarized into Pre-award, Phase I (Design), Phase II (Procurement & Construction), and Phase III (Operation, Data Collection, Reporting) as follows:

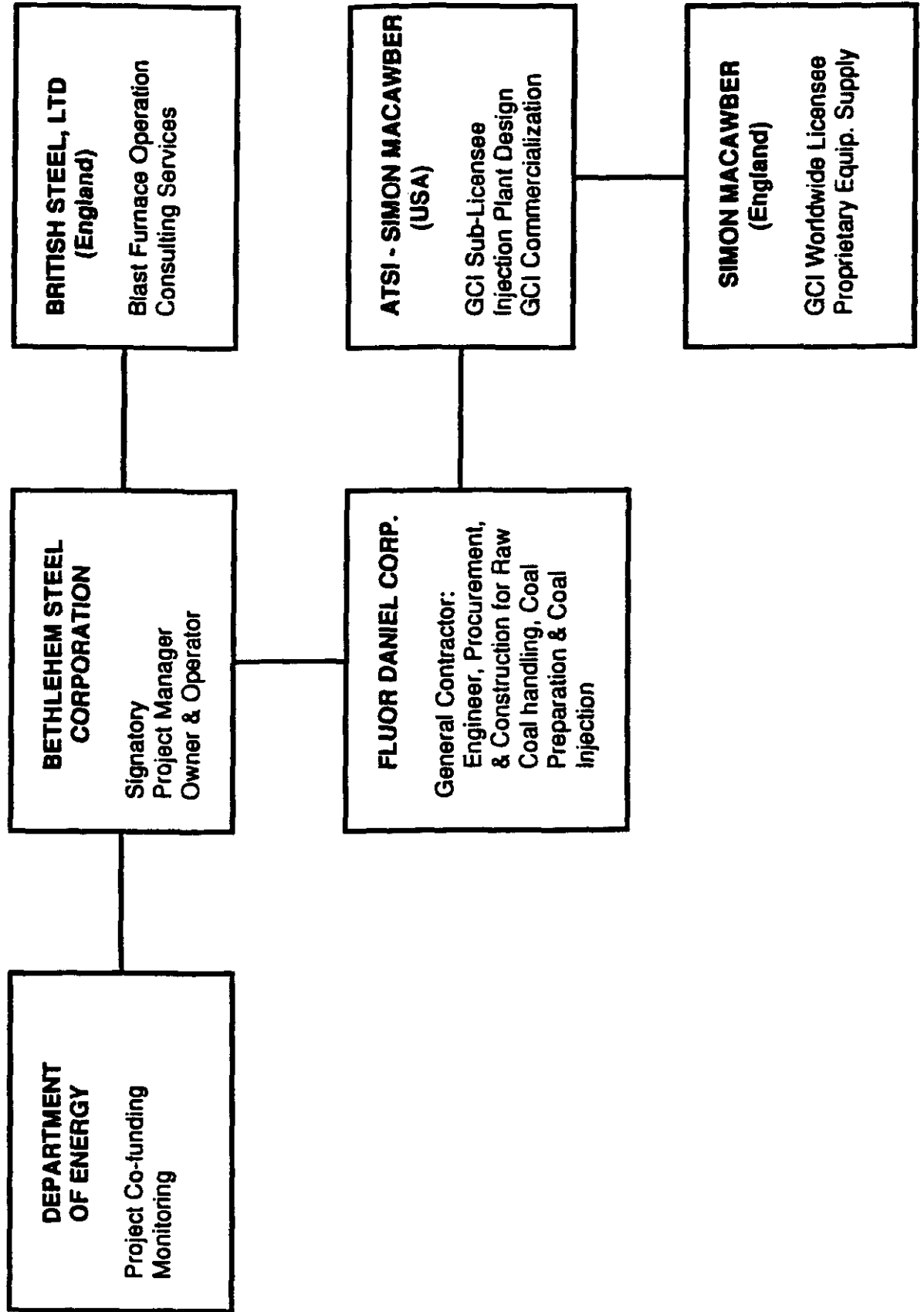
Pre-award	\$90,000
Phase I	\$5,100,000
Phase II	\$133,850,000
Phase III	<u>\$51,610,000</u>
	\$190,650,000
	Total Project Cost

The total project cost is shared between Bethlehem Steel and the DOE as follows:

DOE Share	\$31,259,530	16.4%
Bethlehem Steel Share .	\$159,390,470	83.6%

FIGURE 12

PROJECT CONSTRUCTION ORGANIZATION



COAL TECH'S AIR COOLED SLAGGING COMBUSTOR--Recent Developments

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ABSTRACT

This paper summarizes the past year's progress on commercializing Coal Tech Corp's air cooled, slagging coal combustor. Our effort focused on computer automation for durability and lower operating costs, on coarse coal combustion to reduce coal processing equipment costs, and on dioxin/furan emission control in coal cofired with high chlorine content materials. Tests were performed on a 20 MMBtu/hr combustor, retrofitted to a 17,500 lb/hr, 250 psig, saturated steam, package boiler. Over 300 hours of operation were completed in the past year bringing the total test time on this combustor to about 2000 hours since inception of the Clean Coal Project in 1987. Computer controlled combustor wall temperature and slag replenishment were used to assure the integrity of the combustor wall during these tests. Effective combustion was achieved using coals sizes of 44% passing a 200 mesh and 30% passing a 100 mesh, compared to the usual 70% to 80% passing a 200 mesh. In addition, for fuels containing high levels of chlorine, such as plastic, paper, municipal refuse derived fuel (RDF), and some coals, dioxins and furans can be released from their combustion in conventional systems. A series of tests were performed to measure these emissions in coal mixed with a high concentration of chlorine. It was found that

*-Consultant, +-BJB Associates

coal sulfur level had no discernible impact on these emissions. On the other hand, sorbent injected with a coal plus 1.2% chlorine mixture yielded 25% lower dioxin and furan emissions (equal to 88 nanograms/ cu.m. of gas) .than a 0.1% chlorine content coal and without the sorbent. The test results also suggest that further combustion control of dioxin/furans is possible down to the range of several ng/cu.m. Economic analyses on the combustion of paper/plastic wastes in paper mills and paper/plastic recycling plants at feed rates ranging from 5 tons/day to 700 tons/day show that using the Coal Tech combustor would result in capital costs recoveries in the 1 to 3 year range. Future plans are to operate the combustor for thousands of hours under conditions where the its energy output will be sold to the site host.

INTRODUCTION

This paper summarizes the results of work performed on Coal Tech's commercial scale 20 MMBtu/hour air cooled, slagging coal combustor since the last report at the 1993 Clean Coal Conference [1]. Air cooling recycles the combustor wall heat transfer loss to the combustion air, (making this heat available to the thermodynamic cycle). A portion of the SO₂ and NO_x emissions are controlled inside the combustor. The combustor is designed for new and retrofit boiler applications. Development of the air cooled combustor began in the late 1970's using a 1 MMBtu/hr air cooled cyclone combustor [2], and it continued in the mid 1980's with SO₂ and NO_x control tests in a 7 MMBtu/hr water cooled cyclone combustor [3]. This work was followed by the design, construction, and installation of the present 20 MMBtu/hr, air cooled, combustor between 1984 and 1987 [4]. Between 1987 and 1992 about 1600 hours of test operation were performed using coal, coal water slurry, refuse derived fuel, oil, and gas. The first three years of this demonstration effort, consisting of 800 hours of test operation, were conducted under DOE Clean Coal Program sponsorship. Subsequently, brief tests were conducted on ash vitrification [5] and refuse derived fuel combustion [6] to expand the market potential of the combustor. Most of these tests were performed with manual control of the combustor's operation in order to determine its operating characteristics.

Beginning in 1990, system operation was gradually converted to automatic computer control. This effort accelerated under current DOE sponsored tests [7] which began in 1992 and focus on long duration operation under automatic computer control. Automatic computer control of Coal Tech's slagging combustor makes for significant improvements on its performance capability, which is the focus of the current program. Current objectives are to acquire a data base on durability of combustor components, durability of the auxiliary components needed to operate the combustor, and on the impact of the combustor on the boiler efficiency, fouling and corrosion.

Another key objective is to remove essentially all of the coal sulfur in the combustor with sorbent injection. Finally, the application of the combustor to a wide range of end uses, such as the retrofit and repowering of industrial boilers and power plants, combined cycle industrial power plants, cofiring of coal and waste fuels, firing low grade high ash coals, and vitrifying high carbon content fly ash, is being investigated. To implement this last objective extensive analysis of various power and steam generation systems have been performed. This effort involved extensive contacts with potential users of this technology in the paper, electric utility, and waste disposal industries. Some results of this application effort were reported last year. The present paper will update this application effort. A list of progress reports on the air cooled combustor tests is given in the reference section of last year's Clean Coal paper [1].

In the past year, major progress has been made in bringing the combustor to commercial readiness. Key advances have been in the air cooling control, slag flow control, and fuel feed control. These have resulted in finalizing of the commercial design of this combustor. The 20 MMBtu/hr combustor has been disassembled in order to install the modifications that will be used in the commercial version of this combustor. To validate this final design, the combustor is being reinstalled at a new site where its energy output will be sold to the site owner. This will allow the combustor to operate for 1000's of hours under essentially commercial conditions. During this extended duration operation, Coal Tech will market the combustor for industrial and small scale power generation applications using either owner financed or third party financing of the entire energy system.

Coal Tech's Advanced Air Cooled, Cyclone Coal Combustor

The cyclone combustor is a high temperature ($> 3000^{\circ}\text{F}$) device in which a high velocity swirling gas is used to burn crushed or pulverized coal. The ash is separated from the coal in liquid form on the cyclone combustor walls, from which it flows by gravity toward a port located at the downstream end of the device. A brief description of the operation of Coal Tech's patented, air cooled combustor is as follows (see Figure 1): A gas and oil burner, located at the center of the closed end of the unit, is used as a pilot to pre-heat the combustor and boiler during startup. Dry pulverized coal and sorbent powder for SO_2 control are injected into the combustor in an annular region enclosing the gas/oil burners. Air cooling is accomplished by using a ceramic liner, which is cooled by the swirling secondary air. The liner is maintained at a temperature high enough to keep the slag in a liquid, free flowing state.

Nitrogen oxide emissions are reduced by operating the combustor fuel rich. In the 20 MMBtu/hr combustor, under optimum conditions about two-thirds stack NO_x reductions to 0.26 lb/MMBtu, or 200 ppm (at 3 % O_2) have been measured at about 70% of stoichiometric air/fuel ratio and high combustion efficiencies. Efficient combustion under fuel rich conditions requires either uniform solids feed or combustion gas temperatures in the 3400°F range. With feed non-uniformities and gas temperatures in the 3000 to 3200°F range, the measured combustion efficiencies averaged around 85% at a 0.7 stoichiometric ratio. At this condition, NO_x emissions were reduced to 350 ppm, or 0.48 lb/MMBtu (at 3% O_2), or about 33% below excess air levels.

Sulfur emissions are controlled primarily by sorbent injection into the combustor. Measurement of SO_2 levels were made with a gas sampling probe placed in the stack gas outlet from the boiler. SO_2 reductions with fuel rich conditions in the combustor yielded average 50% to 70% reduction at the stack probe with calcium hydrate injected into combustor at a Ca/S mol ratios of 3 to 4. SO_2 reduction is sensitive to combustion gas temperature and efficiency, sorbent injection location, combustor stoichiometry, and char burnout in the combustor. For example, between 85% and 95% SO_2 reductions were measured with combustor injection of calcium hydrate and below normal gas temperatures. 81% reduction was measured with sorbent injection into the boiler with final combustion air. These results show that very high SO_2 reductions can be achieved. Due to the focus on overall system performance, combustor automation and durability, no systematic tests to optimize the SO_2 reduction have been performed.

Description of the 20 MMBtu/hr Combustor-Boiler Test Facility

The 20 MMBtu/hr combustor was installed on a 17,500 lb/hr steam, 250 psig saturated steam boiler in an industrial plant in Williamsport, PA in early 1987. Figure 2 shows a side view drawing of the combustor attached to the boiler. The coal was pulverized off-site, and stored in a 4 ton capacity coal storage bin next to the boiler house. The coal was metered and fed into a pneumatic line to the combustor. The bin is refilled from a 24 ton coal capacity trailer, parked outside the boilerhouse, without combustor shutdown. Since the combustor's best slag retention is in the 70% to 80% range, it does not meet local particulate emission standards of 0.4 lb/MMBtu. Therefore, a wet particulate scrubber was used for this purpose. Slag drained from the combustor through an opening at the downstream end of the combustor (See figures 1 and 2) into a water filled tank. The slag was removed from the tank by means of a mechanical conveyor and deposited in a drum. The fuel and air streams to the combustor were computer controlled using the combustor's thermal performance as input variables. Diagnostics consisted of measurement of fuel, air and cooling water flows, combustor wall temperatures, and stack gas measure-

ments, including O₂, CO₂, CO, SO₂, NO_x, and HC. Gas samples were taken in the stack above the boiler.

TEST RESULTS IN THE 20 MMBTU/HR COMBUSTOR

Combustor's Operational Results

The combustor is part of a system consisting of the fuel and sorbent feed, the combustor, the slag and ash removal, the boiler, and the stack cleanup equipment. It is only by developing and testing these sub-systems and components, that the combustor can be converted to a commercial product. Therefore, a major part of the development testing of the past several years has been devoted to modifications and improvements in both the combustor and its auxiliary sub-systems. During the past year major progress was made in several key areas to the point where the combustor is now ready for commercial long term operation. The following will describe some of the advances since 1992, which were accomplished in 300 hours of test operations. This brought the total test time on the 20 MMBtu/hr combustor to about 2000 hours..

Coal Feed: A critical element needed to achieve good combustor performance is the uniformity and reliability of the coal feed system, and a major part in the combustor's development has been devoted to this problem. Since the inception of the coal testing in 1987, a screw feeder has been used to assure a steady flow from the coal storage bin to the combustor. Various mechanical and flow smoothing devices were tested to dampen the low frequency (of the order of minutes) and the high frequency (of the order of seconds) fluctuations. This original screw feeder was prone to jamming in the presence of minor tramp material or coal clumps. This rendered it unsuitable for a commercial installation. Accordingly, it was replaced last year with a screw feeder of different design, which has operated trouble free in 100's of hours.

Injection of Coal into the Combustor: Temporally and spatially uniform injection of coal into the combustor is another critical element in combustor performance. In the course of the test effort, a number of axial and off axis injection procedures were tested, which included varying the number of injection points. During the past year, a systematic effort was made to optimize the injection process. Figure 3 shows the percent of fly ash particles retained in the stack particle scrubber as a function of five different injection methods. The ordinate shows the percent retention in the scrubber, and the lower the number the better the combustor's performance as measured by ash retention. The abscissa is the test date. The best performance (i.e. the lowest scrubber retention) was obtained with off axis injection, (tests of 8/19/93, 7/15/93, and 10/20/93), while the poorest

performance was obtained with axial injection. The effect of varying the number of off axis injection points did not yield as clear-cut a result, as the comparison with axial injection.

Computer Control of Combustor Wall Air Cooling: The key to combustor wall durability is maintaining very accurate control of the combustor wall temperature. In this manner the wall of the combustor can be replenished as needed by allowing the slag to freeze off the combustor wall. Prior to the introduction of computer control of the cooling air, control of wall temperature required constant adjustment of the cooling air flow. Computer control also required extensive development. A major problem was adjusting the cooling rate without causing the wall temperature to fluctuate over a wide range. Early last year, the control techniques were perfected to the point where it was now possible to maintain the hot side wall temperature within 2%. This latter result is shown in figure 4 where the temperature at one radial location in the liner is plotted as a function of test time. Steady coal firing was maintained between 11:50 and 23:30 hours (except for a brief flameout at 18:30 hours). The hot side temperature was within a 40°F range of 2000°F (2%) for the entire steady state period. With this control procedure in place it was simple to reline the combustor wall with slag.

Early this year, the 20 MMBtu/hr combustor was disassembled for relocation of the entire test facility. All the combustor wall refractory was removed. Inspection of the metal cooling wall assembly with an ultrasonic depth gage showed no measurable loss of metal wall thickness since its original installation in 1987. A chemical analysis of the refractory liner material showed that much of the inner wall thickness consisted of molten coal ash. This demonstrated that accurate wall temperature control and slag replenishment can maintain combustor liner wall integrity.

Ash Deposits on the Boiler Tubes: One concern in combustor retrofit to an oil designed boiler was excessive deposition of fly ash on convective section boiler tubes. Measurement of the gas temperature at the exit from the boiler showed that after several days of coal fired operation, the gas temperature was about 600°F, compared with 450°F with No.2 oil or gas. The convective section of the boiler is equipped with steam soot blowers. Their impact on boiler output is shown in figure 5, which shows the steam flow for a one day test. At 15:45 hours, a short burst of sootblowing was applied at a time when the stack gas temperature was 620°F. Within seconds the stack temperature decreased to 500°F, and the steam output rose from an average of 12,000 lb/hr to about 13,000 lb/hr. This shows that the tube deposits were dry ash, which are easily removed.

In December 1993, ultrasonic measurements were made on all the boiler tubes. None of the boiler tubes had experienced any measurable metal wall thickness loss since 1000 hours of intermittent coal fired testing was initiated in 1987.

Slag Tap Operation & Slag Removal: The slag tap is susceptible to blockage due to the low viscosity of slag and its high melting temperature. Over the years, a series of designs and procedures were developed that made slag tap blockage an infrequent occurrence. Early last year, an automated slag removal operation was perfected, which is suitable for a fully commercial system. Maintaining an open slag tap is now a routine procedure.

Development continued on a simple and low cost mechanical conveyor for removal system from the slag quench tank. In addition, a water-slag grit separation system was installed which allows the recirculation of the cooling water in the slag tank and the rejection of the heat absorbed by the slag quenching to a water-water heat exchanger without blockage of the heat exchanger passages.

Coarse Coal Particle Size Tests in the Combustor: Economic studies on the application of this combustor to retrofit and repowering of large industrial boilers showed that coal pulverizers that produce 80% through 200 mesh represent a substantial portion of the capital equipment cost. Accordingly, test were performed last year with two coarser coal size distributions. In one case, the coal size was 44% through 200 mesh, and in the other case it was 35% though 100 mesh. These coal sizes can be obtained in lower cost coal crushers and pulverizers. Good combustion efficiencies were obtained, and it is planned to use coarser coal sizes in future operation..

Other Improvements in the Combustor System: In addition to the above, major improvements were made in the following components:

The performance and reliability of the wet stack particle scrubber was improved by redesign of the inlet gas cooling procedure and by redesign of the water/sludge removal outlet.

A pneumatic device was tested for blowing ash deposited in the floor of the boiler furnace and beneath the lower boiler drum to collection points for continuous removal from the flat bottom boiler.

The air cooling concept was successfully extended to the exit nozzle of the combustor, which had previously operated near adiabatically. This reduced the heat load to the refractory front wall of the boiler. This allowed round the clock operation of the combustor at high thermal load. A pair of tests of 24 hours duration at about 3/4 of full combustor rating were implemented.

Control of Dioxins, Furans, Polyaromatic Hydrocarbons (PAH) Emissions from the Combustor.

The emissions of organic micropollutants from fossil fuel and waste fuel combustion sources are subject to increasing regulation. Dioxins and furans are formed during the combustion of fuels containing chlorine, such as plastic, paper, municipal refuse derived fuel (RDF), and some coals. In 1990, Coal Tech performed a series of tests in which coal was cofired with refuse derived fuel. Relatively high dioxin, furan, and PAH emissions were measured. It was tentatively concluded that the high emissions were due to no uniform feeding of the RDF.

In 1993, Coal Tech conducted a series of tests under the DOE SBIR Program to validate this hypothesis. Another objective was to determine whether sulfur in coal and/or other sorbents were effective in reducing dioxin and furan emissions. Uniform feed of chlorine was achieved by pre-mixing a chlorine compound powder with the pulverized coal. In a set of four combustion tests in the 20 MMBtu/hr combustor, it was found that sulfur had no discernible impact on these emissions. On the other hand, a sorbent injected with a coal plus 1.2% chlorine mixture yielded 25% lower dioxin and furan emissions (equal to 88 nanograms/cu.m. of gas) than the 0.1% chlorine content coal and without the sorbent. Also, the SO₂ emission in the former test was lower by 72%.

The 1993 results with uniform feed compare with emissions of 1500 ng/cu.m. in the 1990 test on cofiring coal with RDF having only 0.2% total chlorine. In the latter case, the RDF feed was very non-uniform.

Another key result of the 1993 tests was that the combined dioxins-furans were 10 times lower than those reported for state-of-the-art municipal incinerators at the same stack conditions. It was concluded that additional control of the stack conditions would reduce the total emissions to less than 1 ng/cu.m.. This compares to the most recent EPA proposed standard of 30 ng/cu.m. for large incinerators.

Plans have been formulated to perform additional tests in the combustor to burn chlorine content, waste streams in order to validate that the dioxin-furan emissions can be reduced to 1 ng/cu.m. by sorbent injection and control of stack conditions. These tests will be followed by long duration operation with coal and coal-paper/plastic waste fuels.

TEST PLANS FOR THE 20 MMBTU/HR COMBUSTOR:

After the installation of these improvements, a series of 9 days of combustor operation were implemented in November 1993 under a wide range of operating conditions with no adverse impact on the combustor. At the completion of these tests, it was determined that the combustor had achieved optimum performance in its present configuration, and no significant further improvements could be made without a complete disassembly and refurbishment. Disassembly began early this year. These modifications will improve combustor performance with coarser coal sizes, extend the air cooled sections of the combustor, and optimize the cooling air flow train.

From the various site specific combustor applications studied, it was determined that a major factor in commercial acceptability of the combustor was demonstration of its operation in a commercial environment over extended periods. The existing tests site did not meet this requirements because the only use for the steam output of the boiler was for winter space heating.

Therefore, it was planned to reinstall the 20 MMBtu/hr combustor-boiler at a new site that will serve as power host. By using an atmospheric back pressure turbine, it is possible to generate almost 500 kW of power from the 17,500 lb/hr, 250 psig boiler. It is planned to initially operate the combustor for up to 1000 hours, to be followed by power sales to the host for an additional 1000 hours. Both operating periods will be single shift, 5 days per week. Following this, the combustor will be operated round the clock for up to 6000 hours annually with power sales to the host site. This site will be in an industrial park in the Delaware Valley of Pennsylvania, with reinstallation commencing in the second half of 1994. To allow continuous operation, an on site coarse coal storage and pulverization system will be installed at the new test site.

The early part of this operation will be implemented with a full technical staff. As the confidence in the reliability of the computer control increases, this staff will be reduced to the point where only one or two technicians will monitor the combustor operation. Under those conditions, the revenue from power sales will cover the operating costs and probably produce a profit.

In addition, it is planned to fire the combustor with residual paper/plastic wastes to take advantage of the dioxin control capability of this system. The new combustor installation will demonstrate the commercial combustor design that is being marketed to industrial and small power users in the US and overseas.

APPLICATION OF THE AIR COOLED SLAGGING COMBUSTOR TO RESIDUAL WASTE COMBUSTION

In the 1993 Clean Coal Conference paper [1], five applications of the combustor were briefly described. They were a 20 MW combined gas-steam turbine power plant, a 20 MW steam re-powering plant, a 250 MW retrofit plant, a 100,000 lb/hr steam boiler retrofit, and fly ash vitrification. The following are site specific applications to waste fuel combustion which are feasible due to dioxin/furan control capability of the combustor.

Paper/Plastic Waste from a Cardboard Recycling Plant: The recycling plant produces a cardboard-plastic waste stream at the rate of 5 tons per day which is now landfilled. Incineration in the air cooled combustor would produce 5000 lb/hr of steam and replace natural gas fuel. The cost of fabricating and installing a 6 MMBtu/hr combustor, a used 5000 lb/hr fire tube boiler, auxiliary components was estimated at about two times the annual landfill and gas fuel cost savings. Since the plant already has a boiler operator for the main boiler, no added personnel would be required to operate this system. Therefore the simple payback is 2 years.

Paper Mill Sludge Combustion: This paper mill uses up to 100,000 lb/hr of steam. The plant produces a fiber residue at the rate of 250 tons/day, a water treatment waste of 50 TPD of residue, and it has an on-site landfill that can provide waste fuel at the rate of 142 TPD. Using the air cooled slagging combustor to incinerate all three waste streams will provide 77 MMBtu/hr of energy. This must be supplemented with 62 MMBtu/hr of natural gas or No.2 oil to meet the mill's steam load of 100,000 lb/hr and dry the waste streams.

This requires a 140 MMBtu/hr combustor and its auxiliary components, a waste fuel drying, shredding and fuel transport system, a baghouse, and an used oil/gas type industrial boiler. Its estimated installed cost is such the total annual saving of landfill and gas/oil fuel cost saving will be recovered in less than 1 year.

CONCLUSIONS

The work of the past year has demonstrated the effectiveness of the computer control procedures in enhancing combustor performance and durability. The dioxin control and coarse coal test results have substantially lowered the threshold at which the air cooled combustor technology is economically attractive. With on site residual waste fuels, the combustor is economically attrac-

tive at thermal inputs as low as 6 MMBtu/hr. With coarse coal or coal mine waste or high carbon content fly ash, the combustor is economically attractive in the 10's of MMBtu/hr range.

On the basis of these new economic studies and recent test results, it has been decided to relocate the 20 MMBtu/hr combustor test facility to a site where the boiler's steam power output can be sold as electricity to defray the operating cost and probably produce an operating profit. This will allow long term operation which will be of major assistance to the marketing the combustor to the industrial and small power production sectors in the US and overseas. Fuels will be coal, coal mine waste, residual waste, and high carbon fly ash.

ACKNOWLEDGMENTS

Current test efforts are supported in part by the DOE-Advanced Combustion Technology Program at PETC, and by the DOE Small Business Innovation Research Program.

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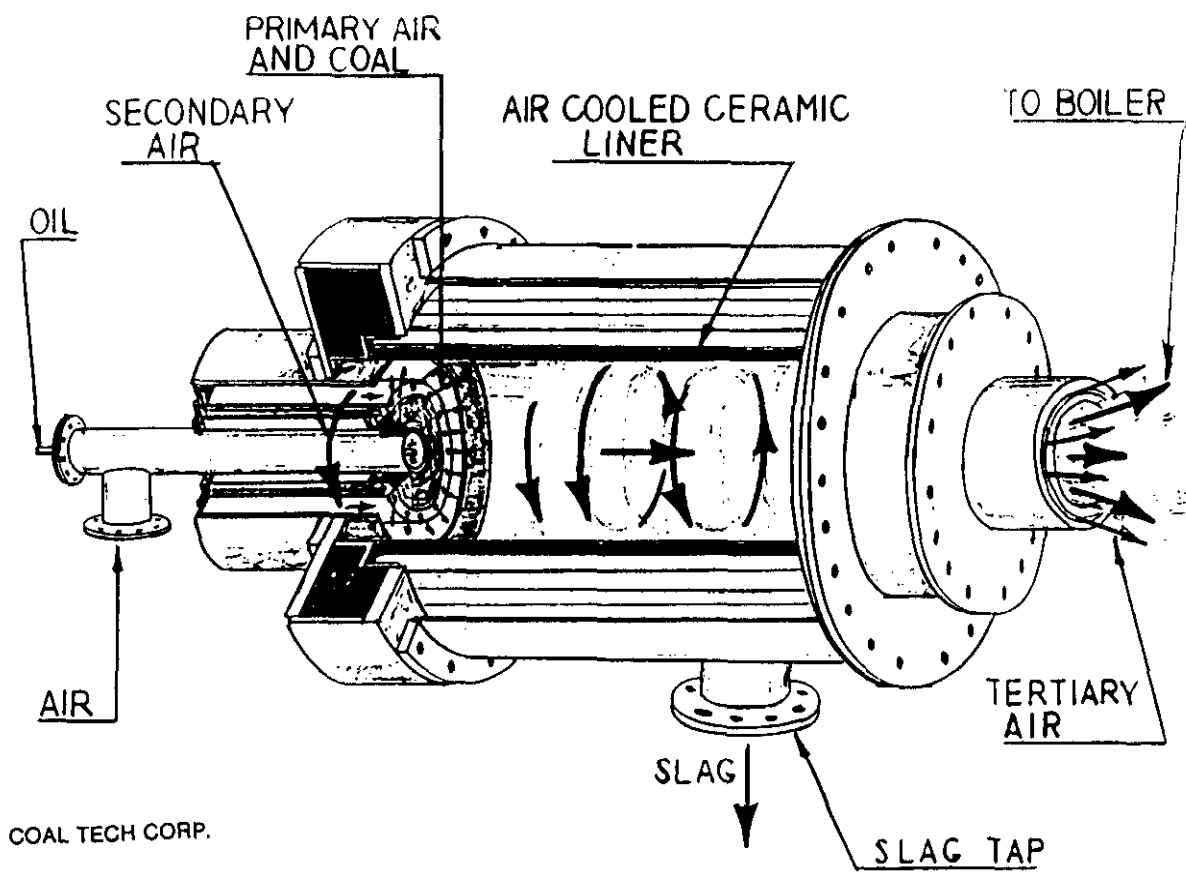


Figure 1: Drawing of the Coal Tech Air Cooled Combustor

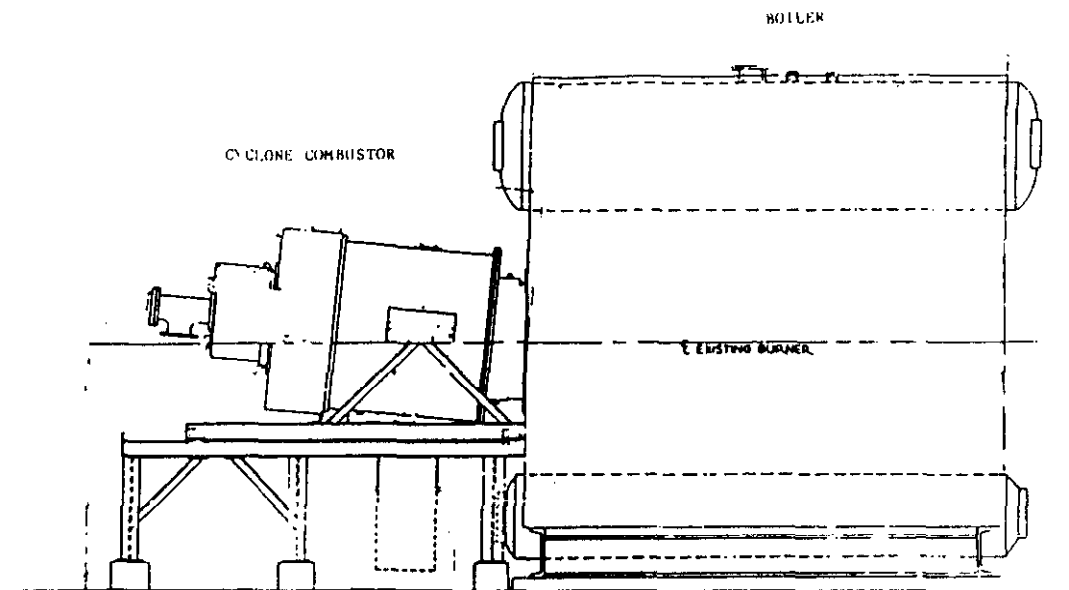


Figure 2: Drawing of the 20 MMBtu/hr Coal Tech Combustor Attached to an Oil/Gas Boiler

Figure 3: Average Scrubber Particle Retention versus Location of Coal Injection into Combustor

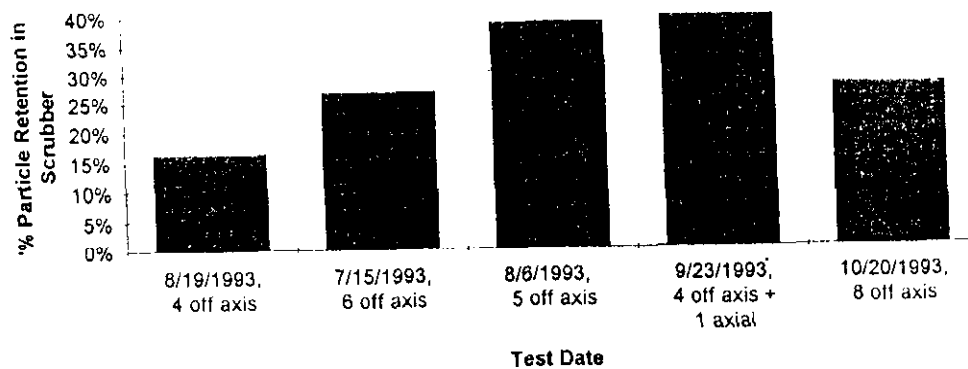


Figure 4: Combustor Wall Temperature: - 7/15/93 Test

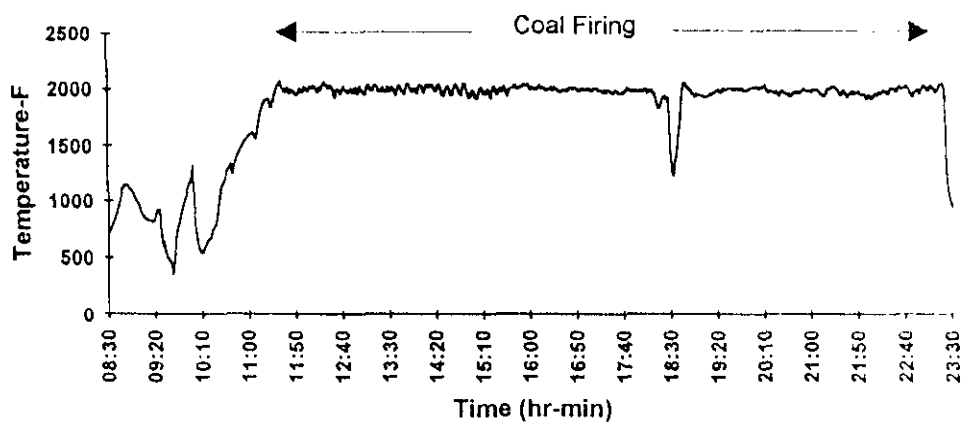
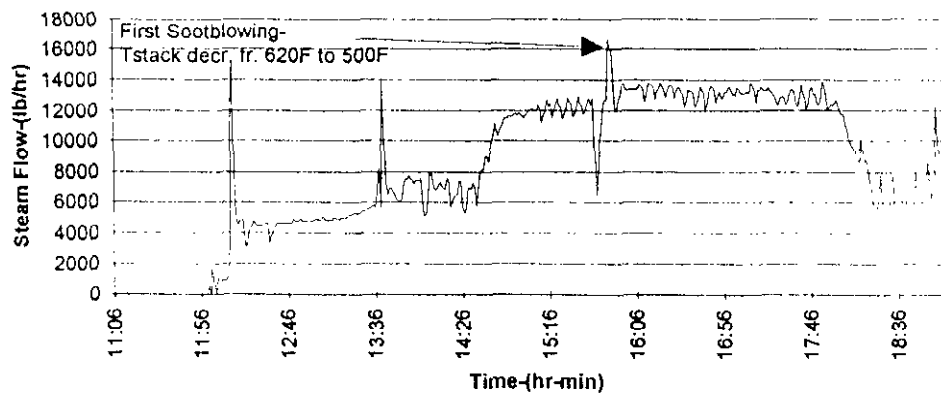


Figure 5: Steam Flow For 9/23/93 Test Showing Flow Increase After Sootblowing at 15:45 Hours



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"CLEAN POWER FROM INTEGRATED COAL-ORE REDUCTION"

ABSTRACT

The clean power from integrated coal-ore reduction (CPICOR™) process integrates two historically distinct processes -- iron-making and electric power generation. COREX® is a novel iron-making technology that eliminates the need for coke production. Under the Clean Coal Technology program, CPICOR Management Company proposes to demonstrate the viability of a commercial scale (3,200 tons per day of liquid iron) COREX® ironmaking plant integrated with a combined cycle power generation (CCPG) facility sized to produce 181 megawatts, of which 150 megawatts will be available for net export. The backbone of the CPICOR project is the innovative COREX® process, in which molten iron is produced by continuous reduction and smelting of iron ore in two integrated unit operations -- a shaft furnace and a melter gasifier. Clean, low BTU (175-210 BTU/SCF) export gas generated in the process will be used to fuel a combined cycle power plant to generate electricity. CPICOR can be operated with a wide range of coal qualities, expanding the use of our nation's vast coal energy reserves. CPICOR technology is less complex and environmentally superior when compared to competing ironmaking and power generation technology. All criteria air pollutants will be reduced by more than 85%, due largely to the inherent desulfurizing capability of the COREX® process and the efficient control systems within the CCPG facility. Coal, not coke, is fed directly to the COREX® melter gasifier. Therefore, CPICOR eliminates the coke plant and its inherent problems of controlling fugitive emissions and toxic and hazardous releases.

TECHNICAL SESSION 9:
SO₂ CONTROL TECHNOLOGIES

Co-Chairs:

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TWO YEARS OF OUTSTANDING AFGD PERFORMANCE, PURE AIR ON THE LAKE'S BAILLY SCRUBBER FACILITY

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Abstract

The "Advanced Flue Gas Desulfurization (AFGD) Demonstration Project" is a \$151.3 million cooperative effort between the U.S. Department of Energy and a project company of Pure Air, a general partnership of Air Products and Chemicals, Inc. and Mitsubishi Heavy Industries America, Inc.

The goal of the AFGD project is to demonstrate that, by combining state-of-the-art technology, highly efficient plant operation and maintenance capabilities, and by-product gypsum sales, significant reductions of SO₂ emissions can be achieved at approximately one-half the life cycle cost of a conventional Flue Gas Desulfurization (FGD) system. Further, this emission reduction is achieved without generating solid waste and while minimizing liquid wastewater effluent.

Briefly, this project entails the design, construction and operation of a nominal 600 MWe AFGD facility to remove SO₂ from coal-fired power plant flue gas at the Northern Indiana Public Service Company's Bailly Generating Station, located approximately 40 miles southeast of Chicago, Illinois. The facility is used to demonstrate a variety of advanced technical and business-related features, during a three-year period of operation

which began in the summer of 1992. The aim of this demonstration is to accelerate near-term commercialization. Key features of the AFGD project are:

- Large single absorber for multiple boilers.
- Single loop absorber with in-situ oxidation to produce commercial gypsum.
- SO₂ removal levels of 95% without chemical additives.
- High velocity co-current absorber.
- Direct injection of pulverized limestone.
- Air rotary sparger.
- Wastewater evaporation system.
- Agglomeration of FGD gypsum powder into PowerChip™ Gypsum.
- "Own-and-Operate" business arrangements.

These and other features allow the scrubber to have improved environmental performance, reduced space requirements, better energy efficiency, and lower costs than conventional first (or second) generation scrubbers. With specific regard to environmental management, this project seeks to demonstrate that air pollution control need not have deleterious solid waste and/or wastewater consequences.

Construction of the scrubber is complete; operations began in June 1992, ahead of schedule and within budget. The Clean Coal demonstration project calls for three years of operations. After the three-year demonstration period, Pure Air on the Lake will continue to Own-and-Operate the scrubber for the next 17 years.

This paper reviews the advanced wet flue gas desulfurization (FGD) design features, and the environmental and business features of the project. Also included are data on the first two years of successful operation.

PROJECT DESCRIPTION

The AFGD demonstration at Bailly station is showcasing several advanced features, compared to conventional FGD systems in operation throughout the United States. These features are described below and illustrated in Figure 1.

Single Large Absorber

Traditionally, an FGD facility contains several SO₂ absorber or "scrubber" modules, with one or two spare modules added to improve system reliability. The AFGD facility at Bailly utilizes a single nominal 600 MWe absorber module. It is the largest capacity absorber module in the United States, and it scrubs all of the flue gases from the Bailly station's two coal-fired boilers. There is no spare or back-up module. Instead, a high degree of system reliability will be demonstrated, as the scrubber is designed for a very high level of availability while removing 95% or more of the SO₂, without the use of performance-enhancing chemical additives.

High Velocity Cocurrent Absorber

The SO₂ absorber utilizes a high velocity concurrent design, in which the scrubbing slurry moves in the same direction as the flue gas flow. Operation at a relatively high flue gas velocity of approximately 20 feet per second allows for a more compact absorber. This feature, combined with the absence of any back-up modules, contributes to improved space requirements for the AFGD system.

Single Loop Scrubber with In-Situ Oxidation

Another space-saving feature is the utilization of the SO₂ absorber to perform three separate functions: prequencher, absorber, and oxidation of scrubber sludge (CaSO₃, calcium sulfite) to gypsum (CaSO₄•H₂O, calcium sulfate). Old FGD systems often employ two or three separate vessels to perform these functions. The AFGD system at Bailly produces a gypsum by-product that is suitable for commercial uses such as wallboard or cement, while older systems produce scrubber sludge which needs to be landfilled as a solid waste.

Direct Limestone Injection

At Bailly, pulverized limestone is injected directly into the SO₂ absorber. The pulverized limestone is purchased from a limestone supplier, thereby eliminating the need for on-site wet grinding systems.

Air Rotary Sparger

A novel device known as an air rotary sparger (ARS) is demonstrated within the absorber module. Basically, the ARS combines the functions of mixing and air distribution within the absorber, thereby facilitating the oxidation of scrubber sludge to gypsum. In a conventional FGD system, mixing would be done by agitators while oxidation air distribution would be performed by a separate fixed sparger arrangement. Merging these functions into one equipment item is expected to provide better mixing within the base of the absorber.

Wastewater Evaporation System

Wastewater disposal often poses a difficult problem for scrubber operators, particularly where the oxidation of scrubber sludge to gypsum is employed. The AFGD project at Bailly is demonstrating a wastewater evaporation system (WES), whereby process wastewater is injected into the flue gas ductwork upstream of the existing electrostatic precipitator (ESP). The hot flue gas evaporates the wastewater, enabling the dissolved solids to be collected by the ESP, along with the fly ash.

PowerChip Gypsum

The AFGD by-product gypsum is in a finely powdered form. However, the Bailly project includes a process to agglomerate and flake part of the by-product gypsum stream, in an attempt to improve the marketability of scrubber gypsum to end-users which are more accustomed to using natural gypsum rock. This PowerChip™ gypsum can be transported more easily and handled with existing equipment at most wallboard and/or cement plants. Pure Air will also attempt to blend fly ash and wastewater treatment solids into the PowerChip™ gypsum by-product. Although these impurities would make the gypsum unacceptable for wallboard applications, it could still be used in cement. Pilot tests have indicated that maximum fly ash loadings of 20% to 30% may be achieved. In combination with wastewater evaporation and the co-production of wallboard grade gypsum, this process may bring coal-fired power generation technology one step closer to the goal of zero-discharge.

On-Site Own and Operate

In addition to state-of-the-art technical features, the AFGD project will showcase a novel business arrangement. Normally, utility companies must contract with several different firms to design and build a scrubber. And once it is built, the utility must operate the scrubber. By contrast, Pure Air designed, financed, built, owns, maintains and operates the Bailly AFGD facility for Northern Indiana as a contractual service. This "own and operate" approach has been employed successfully by Pure Air's parent, Air Products & Chemicals, in other business lines. Its application to flue gas cleanup is attractive to many utilities for a variety of reasons. For example, it allows the utility company to focus on the business of electricity generation and distribution, while Pure Air utilizes its own expertise to own and operate the scrubber facility.

The project was originally selected for award under DOE's Clean Coal Technology Program in September 1988. Following negotiations, Pure Air entered into a long-term flue gas processing agreement with Northern Indiana in October 1989 and a cooperative agreement with DOE in December 1989. Construction activities began in March 1990 and were completed in June, 1992. A three-year demonstration period started in July 1992 to prove the efficacy of AFGD technology with a range of high sulfur United States coals. The demonstration will be followed by a long-term commercial operation period, pursuant to the agreement between Pure Air and Northern Indiana.

Summary of Project Operations

To date, operations have gone well. The scrubber has already exceeded its target of demonstrating 95+% SO₂ removal capability, while producing a commercial gypsum by-product. From start-up 2 June 1992 to 15 June 1994, the AFGD facility removed 133,300 tons of SO₂ at the Bailly Station. Current operations are largely uneventful. Some key operating data are shown in Tables 1, 2 and 3. Future operations will be punctuated by the remaining DOE demonstration tests.

Project Costs

The budget and costs for the AFGD project are summarized in Table 4. The total project budget, including the PowerChip™ gypsum demonstration, is \$151,707,898. Of this amount, DOE is funding \$63,913,200, or 42%. Design and construction of the nominal 600 MWe AFGD facility were completed slightly under budget, operation costs are currently under budget with only one more year of operation remaining under the DOE Cooperative Agreement.

Project Schedule

Groundbreaking for the AFGD facility was held on 20 April 1990, which coincided with the twentieth anniversary of Earth Day. On 2 July 1991, a major accident occurred at the project site when two 14 feet diameter cooling water recirculation lines collapsed. No one was injured. However, the Bailly power plant was shut down for five months. Despite damage to the AFGD facility, and the congestion caused by having a major recovery effort on-site, construction of the AFGD facility was completed two weeks ahead of the original schedule. Start-up occurred on 2 June 1992, and commercial operations commenced on 15 June 1992.

The demonstration period will continue for three years, through 14 June 1995. During this period, six one-month demonstration tests will be performed, to assess scrubber operations with a variety of coals. All coals will be bituminous coals, with sulfur content ranging from 2.0% to 4.5%. The demonstration test scheduled is presented in Table 4.

Note that the first of these demonstration tests (Test No. 3), using the normal coal for the Bailly Station (3.0% to 3.5% sulfur), was successfully completed in September 1992. The second demonstration test (Test No. 4) using 3.5% - 4% sulfur coal was completed in June 1993. The third demonstration test (Test No. 5) using 4.03-4.56 sulfur coal was completed in June 1994. The fourth demonstration test (Test No. 2) was completed in August 1995. Tables 2, 3, and 4 show the SO₂ removal performance during this test at various Boiler Loads.

Additionally, air toxic sampling was conducted by Southern Research Institute in September 1993. This air toxics testing was done under the auspices of DOE's Flue Gas Cleanup R&D Program.

Summary

As of this report, the facility is exceeding all contractual requirements. The AFGD facility is removing in excess of 95% of the SO₂ from Bailly Units #7 and #8, has a 99.9% availability rate, and is producing a wallboard-grade gypsum that is 98% pure.

Table 1. Operations Summary for Pure Air Scrubber at Bailly Station.

	<u>Expected</u>	<u>Achieved</u>
SO ₂ Emissions	90% removal or 1.2 lb/MMBtu, whichever is less stringent	Averaged 94% (during DOE test up to 98+%, or 0.382 lb/MMBtu)
Power Consumption		
24-hour average	<8,650 kW	5,275 kW
Facility Pressure Drop		
24-hour average	<13.5 IWC	3.23 IWC
Particulate Emissions	no net increase	0.04 inlet
(g/SCFD)		0.0071 outlet
F a c i l i t y	99.996%	
Availability-Hrs.-----		
	- 95%	99.996%
MW		
Tons of SO ₂ Removed	C-T-D as of 1 June 94	133,300 first 2 yrs of oper.
Limestone Received	C-T-D as of 1 June 94	218,413
Gypsum Shipped (Wet)	C-T-D as of 1 June 94	391,527
Gypsum Moisture	<10%	6.64
Gypsum Chloride	<120 ppm	33
Gypsum Purity	93%	97.20
Average Water Consumption (GPM)	3,000	1,560
Average Waste Water Flow (GPM)	275	81

Table 2. Wallboard-Grade Gypsum Specifications for Pure Air Scrubber at Bailly Station.

	<u>Expected</u>	<u>Two Year Average</u>
Gypsum Purity (wt. % dry)		
CaSO ₄ - 2 H ₂ O	>93.0%	97.2%
CaSO ₃ - 1/2 H ₂ O	<2.0%	0.07%
SiO ₂	<2.5%	0.5%
Fe ₂ O ₃	<3.5%	0.25%
R ₂ O ₃ (R= metal other than Fe)	----	0.29%
Chlorides	<120 ppm	33 ppm
Free H ₂ O (wt. %)	<10%	6.64%
Mean Particle Size (microns)	>20	50

Table 3. Water Requirements for Pure Air Scrubber at Bailly Station.

	<u>Expected</u>	<u>Two Year Average</u>
Supply Water Flow	<3,000 gpm	1,560 gpm
Wastewater pH	6.0 to 9.0	8.0 to 9.0
Wastewater Total Suspended Solids	<30 ppm	<12 ppm
Wastewater Dissolved Solids		
Chlorides (Cl)	<30,000 ppm	4,560 ppm
Sulfates (SO ₄ ⁺²)	<2,500 ppm	<2,500 ppm
Fluorides (F)	<1,100 ppm	19 ppm
Total Dissolved Solids	<100,000 ppm	14,100 ppm

Table 4. AFGD Demonstration Test Schedule.

<u>Test No.</u>	<u>Coal Sulfur</u>	<u>Schedule</u>
1	2.0% to 2.5%	Summer 1994 (Complete)
2	2.5% to 3.0%	Fall 1994
3	3.0% to 3.5%	Fall 1992 (Complete)
4	3.5% to 4.0%	Spring 1993 (Complete)
5	4.0% to 4.5%	Spring 1994 (Complete)
6	Optimal Conditions	Spring 1995

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**THE CLEAN COAL TECHNOLOGY PROGRAM
10 MWe DEMONSTRATION OF GAS SUSPENSION ABSORPTION
FOR FLUE GAS DESULFURIZATION**

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ABSTRACT

This paper presents a description and the test results of the Gas Suspension Absorption technology demonstration in the Clean Coal Technology project entitled "10 MW Demonstration of Gas Suspension Absorption." AirPol Inc. performed this demonstration project with the cooperation of the Tennessee Valley Authority under a Cooperative Agreement with the United States Department of Energy. This low-cost retrofit project achieved the expected targets of demonstrating the Gas Suspension Absorption system, which is to remove more than 90% of the sulfur dioxide from coal-fired flue gas, while achieving a high utilization of reagent lime.

INTRODUCTION

AirPol, with the assistance of the Tennessee Valley Authority (TVA), demonstrated the Gas Suspension Absorption (GSA) technology in the Clean Coal Technology project entitled "10 MW Demonstration of Gas Suspension Absorption." AirPol performed this demonstration under a Cooperative Agreement awarded by the United States (U.S.) Department of Energy (DOE) in October 1990. This project was selected in Round III of the Clean Coal Technology Program.

This project is the first North American demonstration of the GSA system for flue gas desulfurization (FGD) for a coal-fired utility boiler. This low-cost retrofit project demonstrated that the GSA system, could remove more than 90% of the sulfur dioxide (SO_2) from the flue gas, while achieving a high utilization of reagent lime. TVA furnished its Center for Emissions Research (CER) as the host site and provided operation, maintenance, and technical support during the operations and testing phase of this project. The CER is located at the TVA's Shawnee Fossil Plant near Paducah, Kentucky.

The experience gained by AirPol in designing, fabricating, and constructing the GSA equipment through the execution of this project will be used for future commercialization of the GSA technology. The results of the operation and testing phase will be used to further improve the GSA system design and operation.

The specific technical objectives of the GSA demonstration project are the following:

- Effectively demonstrate SO_2 removal in excess of 90% using high-sulfur U.S. coal.
- Optimize design and operating parameters to increase the SO_2 removal efficiency and the lime utilization.
- Compare the SO_2 removal efficiency of the GSA technology with existing spray dryer/electrostatic precipitator (SD/ESP) technology.

DOE issued an amendment to the Cooperative Agreement to include the additional scope of work for air toxics testing and also the operation and testing of a 1 MWe pulse jet baghouse (PJBH) pilot plant in cooperation with TVA and the Electric Power Research Institute (EPRI). The two-fold purpose of this additional work is the following:

- Determine the air toxics removal performance of the GSA technology.
- Compare the SO₂, particulate, and air toxics removal performance between GSA/ESP and GSA/PJBH systems.

The PJBH can treat flue gas removed either upstream or downstream of the ESP. The testing of the PJBH was conducted for both configurations.

The total budget for the project with the added scope of work was \$7,720,000; however, the project cost was under the budget. The favorable variance resulted mainly from actual material and construction costs being much lower than the original estimate. The performance period of the project, including the air toxics measurements, PJBH testing, and report preparation was from November 1990 to March 1994.

AirPol began the design work on this project in November 1990, shortly after award of the Cooperative Agreement by DOE in October 1990. At the outset of the project, site access at the CER was delayed for one year by TVA to allow the completion of another project. That caused a one-year delay in this Clean Coal Technology project. The design phase of the GSA project was completed in December 1991. The fabrication and construction of the GSA unit was completed ahead of schedule in early September 1992. The planned operation and testing of the demonstration unit began in late October 1992 and was completed in mid-March 1994.

HISTORY OF THE GSA TECHNOLOGY

The GSA process is a novel concept for FGD that was developed by AirPol's parent company, F.L. Smidth miljo a/s in Copenhagen, Denmark. The process was initially developed as a

cyclone preheater system for cement kiln raw meal (limestone and clay). This innovative system provided both capital and energy savings by reducing the required length of the rotary kiln and lowering fuel consumption. The GSA system also showed superior heat and mass transfer characteristics and was subsequently used for the calcination of limestone, alumina, and dolomite. The GSA system for FGD applications was developed later by injecting lime slurry and the recycled solids into the bottom of the reactor to function as an acid gas absorber.

In 1985, a GSA pilot plant was built in Denmark to establish design parameters for SO₂ and hydrogen chloride (HCl) absorption for waste incineration applications. The first commercial GSA unit was installed at the KARA Waste-to-Energy Plant at Roskilde, Denmark, in 1988. Currently, there are ten GSA installations in Europe, and all are municipal solid waste incinerator applications.

With the increased emphasis on SO₂ emissions reduction by electric utility and industrial plants as required by the Clean Air Act Amendments of 1990, there is a need for a simple and economic FGD process, such as GSA, by the small to mid-size plants where a wet FGD system may not be feasible. The GSA FGD process, with commercial and technical advantages expected to be confirmed in this demonstration project, will be a viable alternative to meet the needs of the U.S. utility industry and the industrial boilers.

GSA FGD PROCESS DESCRIPTION

The GSA FGD system, as shown in the Figure 1 Process Flow Diagram, includes:

- A circulating fluidized bed reactor.
- A separating cyclone incorporating a system for recycling the separated material to the reactor.
- A lime slurry preparation system which proportions the slurry to the reactor via a dual-fluid nozzle.

- A dust collector which removes fly ash and reaction products from the flue gas stream.

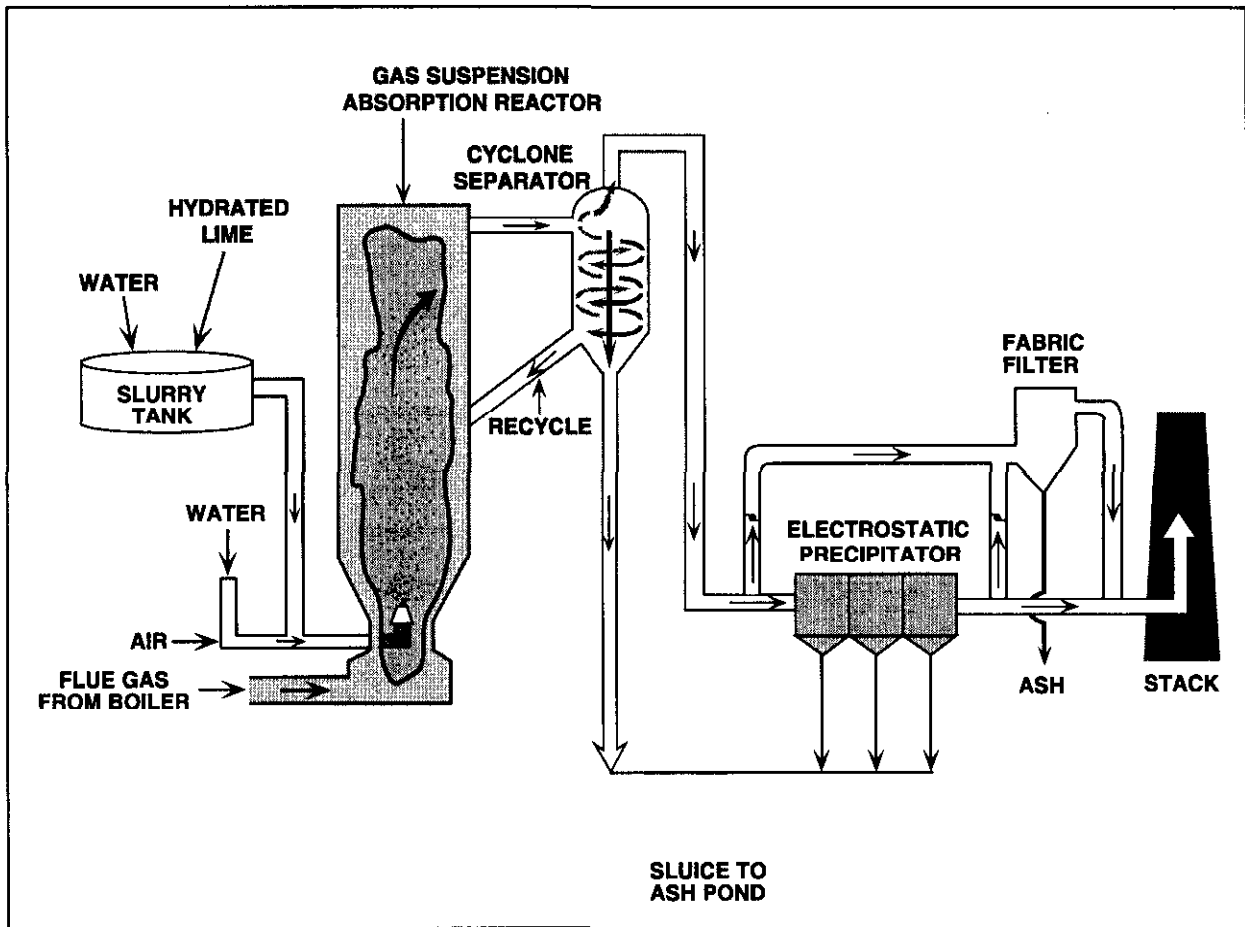


Figure 1. Gas Suspension Absorption Process Flow Diagram

The flue gas from the boiler air preheater is fed into the bottom of the circulating fluidized bed reactor where it is mixed with the suspended solids that have been wetted by the fresh lime slurry. The suspended solids consist of reaction products, residual lime, and fly ash. During the drying process in the reactor, the moisture in the fresh lime slurry, which coats the outer surface of the suspended solids, evaporates. Simultaneously, the lime particles in the slurry undergo a chemical reaction with the acid components of the flue gas, SO_2 and HCl , capturing and neutralizing them.

The partially cleaned flue gas flows from the top of the reactor to the separating cyclone and then to an ESP (or a fabric filter), which removes the dust and ash particles. The flue gas, which has now been cleaned, is then released into the atmosphere through the stack.

The cyclone separates most of the solids from the flue gas stream. Approximately 95% to 99% of these collected solids are fed back to the reactor via a screw conveyor, while the remaining solids leave the system as a byproduct material. Some of these solids recirculated to the reactor are still reactive. This means that the recirculated lime is still available to react and neutralize the acid components in the flue gas.

The pebble lime is slaked in a conventional, off-the-shelf system. The resulting fresh slaked lime slurry is pumped to an interim storage tank and then to the dual-fluid nozzle. The slurry is diluted with trim water prior to being injected into the reactor.

Automatic Process Adjustment

An effective monitoring and control system automatically ensures that the required level of SO₂ removal is attained while keeping lime consumption to a minimum. This GSA control system, which is shown in Figure 2, incorporates three separate control loops:

1. Based on the flue gas flow rate entering the GSA system, the first loop continuously controls the flow rate of the recycled solids back to the reactor. The large surface area for reaction provided by these fluidized solids and the even distribution of the lime slurry in the reactor, provides for the efficient mixing of the lime with the flue gas. At the same time, the large volume of dry material prevents the slurry from adhering to the sides of the reactor.
2. The second control loop ensures that the flue gas is sufficiently cooled to optimize the absorption and reaction of the acid gases. This control of flue gas temperature is achieved by the injection of additional water along with the lime slurry. The amount of

water added into the system is governed by the temperature of the flue gas exiting the reactor. This temperature is normally set a few degrees above flue gas saturation temperature to insure that the reactor solids will be dry so as to reduce any risk of acid condensation.

3. The third control loop determines the lime slurry addition rate. This is accomplished by continuously monitoring the SO_2 content in the outlet flue gas and comparing it with the required emission level. This control loop enables direct proportioning of lime slurry feed according to the monitored results and maintains a low level of lime consumption.

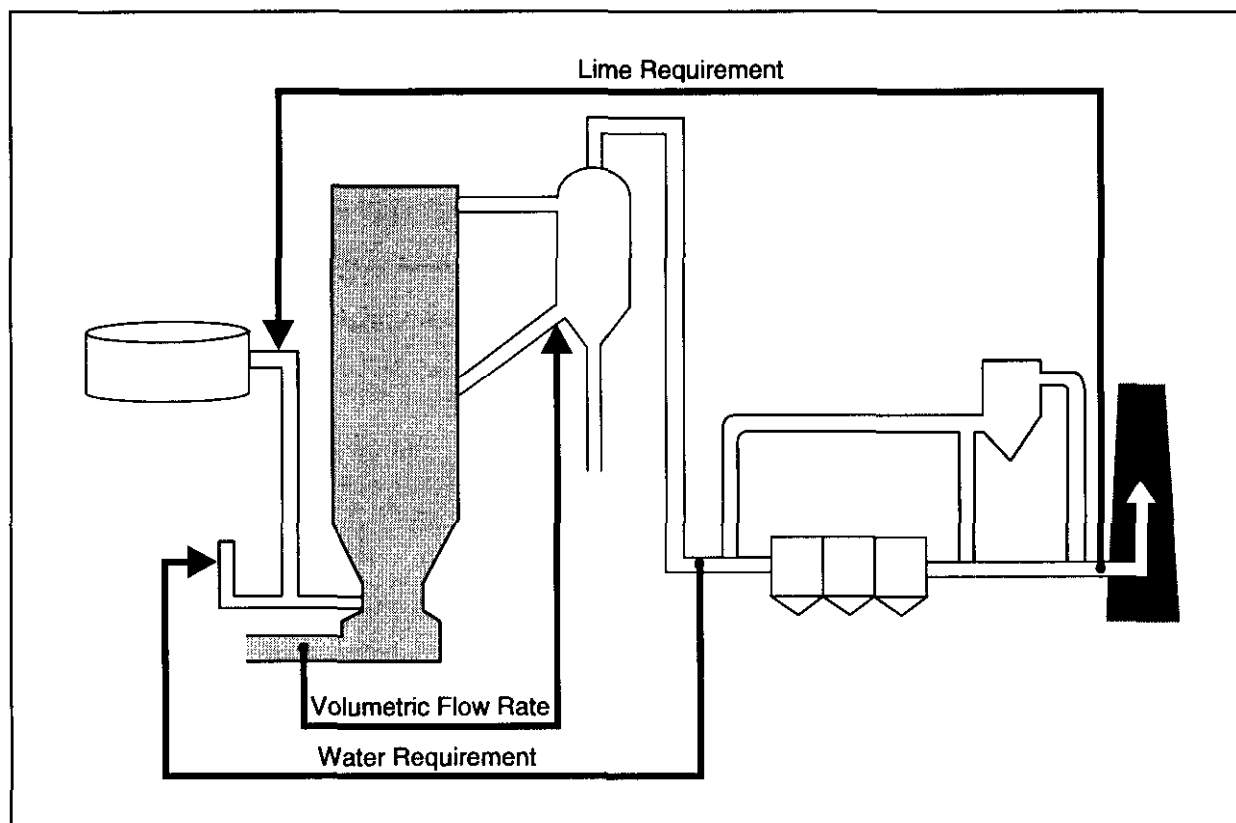


Figure 2. Gas Suspension Absorption Control System

COMPARISON OF GSA PROCESS WITH COMPETING TECHNOLOGY

Simplicity is the key feature of the GSA system. The advantages of the GSA system over competing technologies are summarized as follows:

Slurry Atomization

The major difference between the GSA and the competing technologies lies in how the reagent is introduced and used for SO₂ absorption. A conventional semi-dry scrubber:

- Requires a costly and sensitive high-speed rotary atomizer or a high-pressure atomizing nozzle for fine atomization,
- Absorbs SO₂ in an "umbrella" of finely atomized slurry with a droplet size of about 50 microns,
- May require multiple nozzle heads or rotary atomizers to ensure fine atomization and full coverage of the reactor cross section, and
- Uses recycle material in the feed slurry necessitating expensive abrasion-resistant materials in the atomizer(s).

The GSA process, on the other hand:

- Uses a low-pressure, dual-fluid nozzle,
- Absorbs SO₂ on the wetted surface of suspended solids with superior mass and heat transfer characteristics,
- Uses only one spray nozzle for the purpose of introducing slurry and water to the reactor, and
- Uses dry injection of recycle material directly into the reactor, thereby avoiding erosion problems in the nozzle or technical limitation on the amount of solids that can be recycled.

Simple and Direct Method of Lime/Solid Recirculation

The recirculation of used lime is the trend for semi-dry scrubbing systems. The recirculation of solids in the GSA system is accomplished using a feeder box under the cyclone, which introduces the material directly into the reactor. The recirculation feature commonly used in most other semi-dry processes has an elaborate ash handling system to convey and store the ash. The method of introducing the recirculated material is usually by mixing it with the fresh lime slurry. The presence of ash in the lime slurry may cause a sediment problem in the slurry lines and excessive nozzle wear.

High Acid Gas Absorption

The GSA reactor is capable of supporting an extremely high concentration of solids (recirculated material) inside the reactor, which acts like a fluidized bed. This concentration will normally be as high as 200-800 grains/scf. These suspended solids provide a large surface area for contact between the lime slurry (on the surface of the solids) and the acidic components in the flue gas. This high contact area allows the GSA process to achieve levels of performance that are closer to those of a wet scrubber, rather than a dry scrubber. Since drying of the solids is also greatly enhanced by the characteristic large surface area of the fluidized bed, the temperature inside the reactor can be reduced below that of the typical semi-dry scrubber. This lower operating temperature facilitates the acid gas removal in the GSA system and helps it achieve SO₂ removal levels which are comparable to a wet scrubber.

Low Lime Consumption / Minimum Waste Byproduct Residue

The design of the GSA reactor allows for more efficient utilization of the lime slurry because of the high internal recirculation rate and precise process control. The higher lime utilization (up to 80%) lowers the lime consumption, thereby minimizing one of the major operating costs. In addition, the lower lime consumption reduces the amount of byproduct generated by the system.

Low Maintenance Operation

Unlike the typical semi-dry scrubbers, the GSA system has no moving parts inside the reactor, thus ensuring relatively continuous, maintenance-free operation. The orifice diameter of the GSA injection nozzle is much larger than that used in a conventional semi-dry process, and there is little chance for it to plug. Nozzle wear is also minimized. Should the need for replacing the nozzle arise, it can be replaced in a few minutes. The cyclone also has no moving parts. Both the reactor and the cyclone are fabricated from unlined carbon steel.

The GSA process also has few pieces of equipment. Most of the equipment is in the lime slurry preparation area, which typically is an off-the-shelf item, and the technology is well known.

No Internal Buildup

By virtue of the fluidized bed inside the reactor, the inside surface of the reactor is continuously "brushed" by the suspended solids and is kept free of any buildup. Internal wall buildup can be a problem with the conventional semi-dry scrubber. There is also no wet/dry interface on any part of the equipment and this avoids any serious corrosion problem.

Modest Space Requirements

Due to the high concentration of suspended solids in the reactor, more than adequate reaction occurs in a relatively short period of time. A high flue gas velocity of 20 to 22 feet per second as compared to 4 to 6 feet per second for a semi-dry scrubber and the shorter residence time of 2 to 3 seconds as compared to 10 to 12 seconds for a semi-dry scrubber, allow for a smaller diameter reactor which leads to a considerable reduction in space requirements.

Short Construction Period

The compact design of the GSA unit requires less manpower and time to be erected as compared to the typical semi-dry scrubbers. Despite the relatively complicated tie-ins and extremely constrained work space, the retrofit GSA demonstration unit at the TVA's CER was erected in three and a half months.

Heavy Metals Removal

Recent test results from waste incineration plants in Denmark indicate that the GSA process is not only effective in removing acidic components from the flue gas but is also capable of removing heavy metals, such as mercury, cadmium, and lead.

PROJECT STATUS AND KEY MILESTONES

The project schedule and tasks involved in the design, construction, and operation and testing phases are as follows:

Phase I - Engineering and Design		Start - End
1.1	Project and Contract Management	11/01/90-12/31/91
1.2	Process Design	11/01/90-12/31/91
1.3	Environmental Analysis	11/01/90-12/31/91
1.4	Engineering Design	11/01/90-12/31/91
Phase II - Procurement and Construction		
2.1	Project and Contract Management	01/01/92-09/30/92
2.2	Procurement and Furnish Material	01/01/92-04/30/92
2.3	Construction and Commissioning	05/01/92-09/30/92
Phase III - Operating and Testing		
3.1	Project Management	10/01/92-12/31/94
3.2	Start-up and Training	10/01/92-10/14/92
3.3	Testing and Reporting	10/15/92-12/31/94

The parametric optimization tests were completed on schedule in August 1993. Following the air toxics testing, which was finished in October 1993, there was a 28-day, round-the-clock demonstration run from late October to late November 1993 and a 14-day, around-the-clock PJBH demonstration run from late February to mid-March 1994. All testing has been conducted and the project reports are currently being prepared.

TEST PLAN

A test plan was prepared to depict in detail the procedures, locations, and analytical methods to be used in the tests. All of the following objectives were achieved by testing the GSA system:

- Optimization of the operating variables.
- Determination of Ca/S stoichiometric ratios for various SO₂ removal efficiencies.
- Evaluation of erosion and corrosion at various locations in the system.
- Demonstration of 90% or greater SO₂ removal efficiency when the boiler is fired with high-sulfur coal.
- Determination of the air toxics removal performance.
- Evaluation of the PJBH performance in conjunction with the GSA process.

Optimization Tests

The optimization of the SO₂ removal efficiency in the GSA system was accomplished through the completion of a statistically-designed factorial test plan. For each test series, the GSA system was set to operate at a certain combination of operating parameters. The results of these test series are analyzed statistically to determine the impact of the operating parameters, thus arriving at the optimum operating point for the GSA process at the various operating conditions expected in future applications. Operating parameters that may be varied in different test series for process optimization purposes are the following:

- Inlet flue gas flow rate
- Inlet SO₂ concentration (dependent on availability of different coal)
- Inlet flue gas temperature
- Inlet dust loading

- Solids recirculation rate
- Ca/S Stoichiometric ratio
- Approach-to-saturation temperature
- Coal chloride level

Data Collection

The following data were sampled and recorded during the tests by either the computerized data sampling and recording system (via field mounted instruments) or by manual field determinations:

- Inlet flue gas flow into the system
- SO₂ loading at the system inlet, SO₂ loading at the ESP inlet and outlet
- Flue gas temperature at the system inlet, the reactor outlet, and the ESP outlet
- Particulate loading at the ESP inlet and outlet
- Fresh lime slurry flow rate and composition (for lime stoichiometry calculation)
- Water flow rate
- Wet-bulb temperature at the reactor inlet (for approach-to-saturation temperature calculation)
- Coal analysis (proximate and ultimate)
- Lime analysis
- Byproduct rate and composition
- Water analysis
- Power consumption

Preliminary Testing

Immediately after the dedication of the AirPol GSA demonstration plant in late October 1992, a series of preliminary tests was begun. The purpose of these tests was to investigate the operating limits of the GSA system as installed at the CER. The results from several of the preliminary tests completed at the CER in November and December were very interesting, and these results were used as the basis for the design of the factorial test program. During one of the preliminary tests, the approach-to-saturation temperature in the reactor was gradually decreased and the overall system (reactor/cyclone and ESP) SO₂ removal efficiency was monitored over this four-day test. The overall system SO₂ removal efficiency increased from about 65% to more than 99% at the closest approach-to-saturation temperature (5°F). The other conditions, which remained constant, were 320°F inlet flue gas temperature, 1.40 moles

$\text{Ca}(\text{OH})_2$ /mole inlet SO_2 for the lime stoichiometry, and essentially no chloride in the system. The SO_2 removal results from this test are shown in Figure 3.

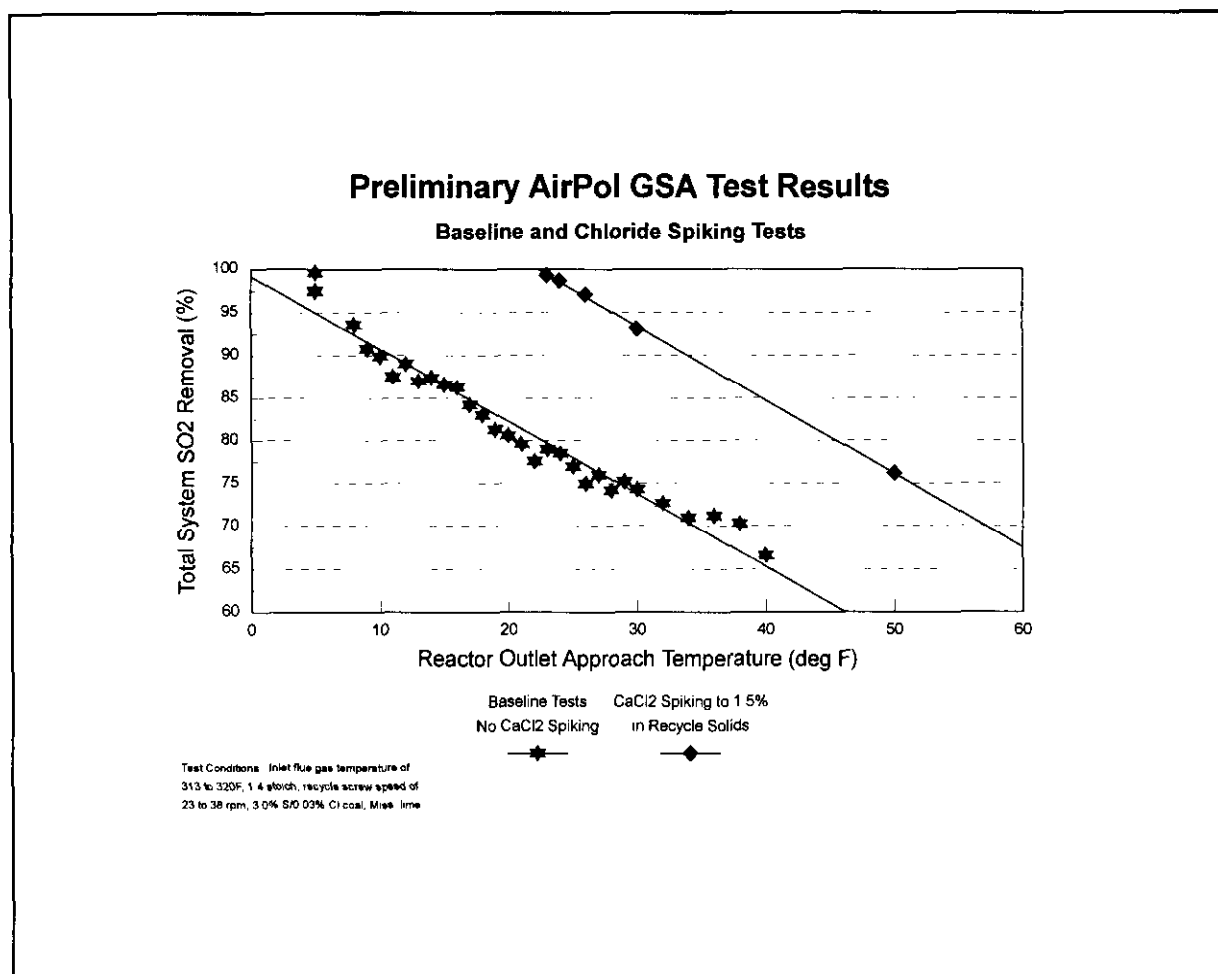


Figure 3. Preliminary AirPol GSA Test Results

The data from this test show that the SO_2 removal efficiency increased dramatically as the flue gas temperature in the reactor more closely approached the saturation temperature of the flue gas, with the incremental increases in the SO_2 removal becoming more and more significant as the approach-to-saturation temperature declined. The ability of the GSA system to operate at this close approach-to-saturation temperature without any indication of plugging problems was surprising. Later analysis showed that the moisture level in the solids remained below 1%.

A second extended test was run during December 1992. This test was run at the same conditions as the previous test, except that in this test, calcium chloride was added to the system to simulate the combustion of a high-chloride (about 0.3%) coal. Previous work by TVA at the CER had demonstrated that spiking these semi-dry, lime-based FGD processes with a calcium chloride solution adequately simulated a high chloride coal application. Again, the approach-to-saturation temperature was gradually decreased over a four-day period with all other conditions held constant and the overall system SO₂ removal efficiency was monitored. The preliminary results from this second test are also shown in Figure 3 above.

The overall system SO₂ removal efficiency increased from about 75% at the high approach-to-saturation condition to essentially 100% at the closer approach-to-saturation temperature (23°F). No attempt was made to operate the system at the close approach-to-saturation temperatures used in the first test because the SO₂ removal efficiency was approaching 100%. In addition, there were initially some concerns about the secondary effect of calcium chloride addition. Calcium chloride is an ionic salt that tends to depress the vapor pressure of water in the system and thus, slows the evaporation of water from the slurry. Calcium chloride is also a hygroscopic material, which means it has the ability to absorb moisture from the humid flue gas. The increased moisture in the "dry" solids allows more reaction with SO₂, but also increases the potential for plugging in the system. The easiest method for mitigating this potential for plugging is to increase the approach-to-saturation temperature in the reactor. However, the moisture levels in the solids during this test remained below 1%, even at the closest approach-to-saturation temperature.

Another interesting finding from the preliminary testing is that the GSA process is capable of supporting a very high level of recirculation material in the reactor. This high solid concentration inside the reactor is the reason for the superior drying characteristics of the GSA system. Based on the results from these initial tests, the recycle rate back to the reactor was doubled prior to starting the factorial testing.

Factorial Testing

The primary focus of the recent GSA testing was the completion of the statistically-designed factorial test program. The purpose of this factorial testing was to determine the effect of the process variables on the SO₂ removal efficiency in the reactor/cyclone and the ESP.

Based on the successful preliminary testing, the major process design variables were determined, levels for each of these variables were defined, and an overall test plan was prepared. The major variables were approach-to-saturation temperature, lime stoichiometry, fly ash loading, coal chloride level, flue gas flow rate, and recycle screw speed. Two levels were determined for nearly all of the variables and these variables and levels are shown in the Table 1 below. The one exception was the approach-to-saturation temperature where three levels were defined, but the third level was only run for those tests at the lower coal chloride level.

Major Variables and Levels for Factorial Testing Table		
Variable		Level
Approach-to-saturation temperature	°F	8 ^a , 18, and 28
Ca/S	moles Ca(OH) ₂ /mole inlet SO ₂	1.00 and 1.30
Fly ash loading	gr/acf	0.5 and 2.0
Coal chloride level	%	0.02 and 0.12
Flue gas flow rate	kscfm	14 and 20
Recycle screw speed	rpm	30 and 45
^a 8°F level run only at the low-chloride level		

Table 1. Major Variables and Levels for Factorial Testing

Although the preliminary chloride spiking tests had not been run at an approach-to-saturation temperature below 23°F, the decision was made to complete these chloride-spiking factorial tests at an 18°F approach-to-saturation temperature. There was some risk in this decision because the water evaporation rate is decreased at the higher chloride levels. However, based on previous test work at the CER, the expectation was that at the lower chloride levels in this test plan, equivalent to a coal chloride level of 0.12%, the GSA system could operate at the 18°F approach-to-saturation temperature condition.

RESULTS OF FACTORIAL TESTING

SO₂ Removal Efficiency

The overall system SO₂ removal efficiency results from these factorial tests have been analyzed, and several general relationships have become apparent. First, as was expected based on the previous testing at the CER, significant positive effects on the SO₂ removal efficiency in the system came from increasing the lime stoichiometry and other factors such as increasing the coal chloride level or decreasing the approach-to-saturation temperature. Increasing the recycle rate resulted in higher SO₂ removal, but the benefit appeared to reach an optimum level, above which further increases in the recycle rate did not seem to have a significant effect on SO₂ removal. Increasing the flue gas flow rate had a negative effect on the SO₂ removal in the system.

The overall system SO₂ removal efficiency during these tests ranged from slightly more than 60% to nearly 95%, depending on the specific test conditions. The higher SO₂ removal efficiency levels were achieved at the closer approach-to-saturation temperatures (8 and 18°F), the higher lime stoichiometry level (1.30 moles Ca(OH)₂/mole inlet SO₂), and the higher coal chloride level (0.12%). The lower SO₂ removal efficiency levels were achieved at the higher approach-to-saturation temperature (28°F), the lower lime stoichiometry level (1.00 mole Ca(OH)₂/mole inlet SO₂), and the lower coal chloride level (0.02-0.04%). The data from these factorial tests completed at these conditions are shown in Figure 4. The slight scatter in the data in this figure is due to the variations in the other major process variables in these tests (i.e., flue gas flow rate,

recycle screw speed, etc.). Most of the SO₂ removal in the GSA system occurs in the reactor/cyclone, with only about 2 to 5 percentage points of the overall system removal occurring in the ESP. There is substantially less SO₂ removal in the ESP than in the previous testing at the CER, but the overall system SO₂ removal efficiencies appear to be comparable with the GSA process for most test conditions.

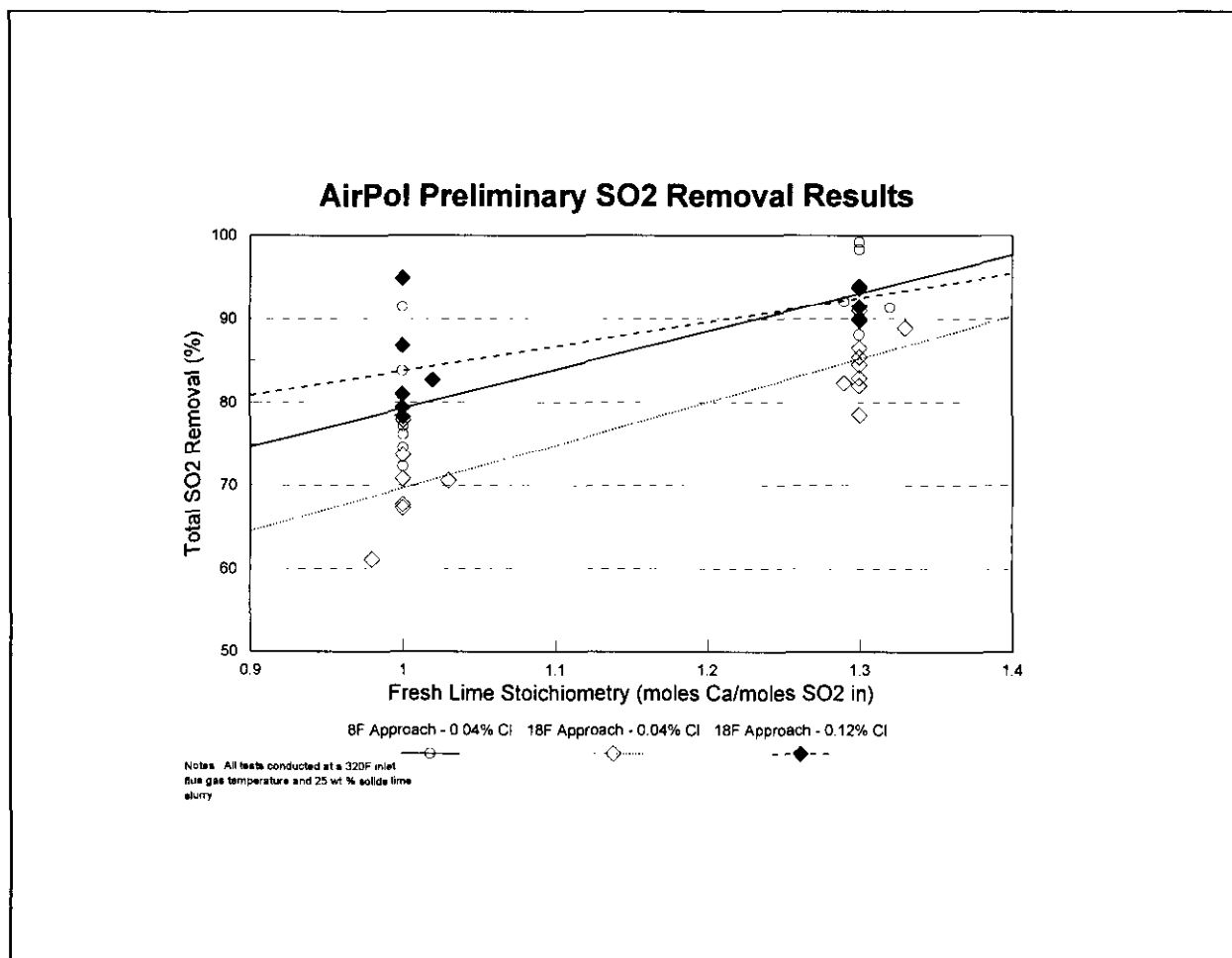


Figure 4. Overall System SO₂ Removal Results from the GSA Factorial Testing

As one would expect, the lime stoichiometry level, which was tested at 1.00 and 1.30 moles Ca(OH)₂/mole inlet SO₂, seems to have the most significant effect on the SO₂ removal efficiency in the GSA system.

The approach-to-saturation temperature, which was evaluated at three levels of 8, 18, and 28°F for the low coal chloride conditions and the two levels of 18 and 28°F for the higher coal chloride condition, appears to be the second most important variable in the GSA system in terms of the overall system SO₂ removal efficiency.

The third most important variable seems to be the chloride level in the system. Two coal chloride levels were tested, the baseline coal chloride level of 0.02 to 0.04% and the equivalent of a 0.12% coal chloride level. The higher chloride level was achieved by spiking the feed slurry with a calcium chloride solution.

One of the most surprising results of this factorial testing was the ability of the GSA system to operate at an 8°F approach-to saturation temperature at the low-chloride condition without any indication of plugging. This is even more impressive given the very low flue gas residence time in the reactor/cyclone. The second interesting result of this testing was the ability of the GSA system to operate at the 18°F approach-to-saturation temperature at the higher chloride level. In the preliminary testing at a much higher coal chloride level (0.3%), the lowest approach-to-saturation temperature tested was 23°F. No operating problems were encountered in the tests completed at the 0.12% coal chloride level and 18°F approach-to-saturation temperature conditions. In fact, the average moisture level in the solids remained below 1.0% in all of these factorial tests, even at the higher coal chloride level.

ESP Performance

The ESP installed at the CER is a relatively modern, 4-field unit with 10 inch plate spacing, similar in design to several full-scale ESPs installed on the TVA Power System. This unit has 23-feet-high plates with 8 parallel gas passages. The specific collection area (SCA) of the unit is about 440 ft²/kacfm under the cooled, humidified flue gas conditions downstream of the reactor/cyclone. (For the untreated flue gas at 300°F, i.e., in a fly-ash-only application, the SCA of this ESP is about 360 ft²/kacfm.)

The particulate removal performance of this ESP was determined for each of the factorial tests, even though this was not the primary focus of the testing. The most important result of this particulate testing was that the emission rate from the ESP was substantially below the New Source Performance Standards (NSPS) for particulates (0.03 lb/MBtu) at all of the test conditions evaluated as shown in Figure 5. The typical emission rate was 0.010 lb/MBtu. The particulate removal efficiency in the ESP for nearly all of the tests was above 99.9% and the outlet grain loadings were below 0.005 gr/acf.

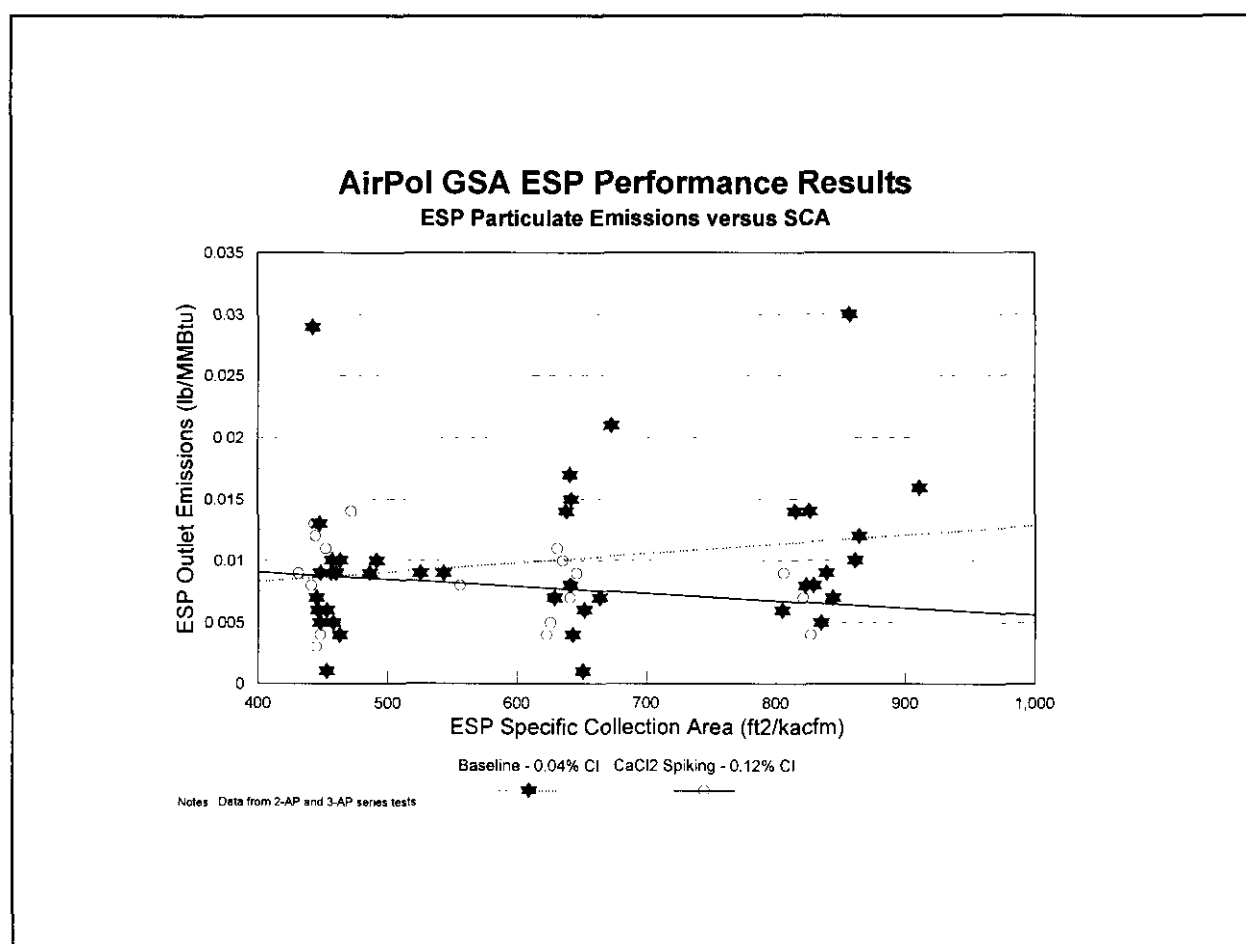


Figure 5. ESP Performance Results from the GSA Factorial Testing

However, during the testing there were disturbing indications of low power levels in the first field of the ESP, particularly in those tests involving chloride spiking. In some of these chloride-spiking tests completed at the high flue gas flow rate (20,000 scfm), the power level in the first field was only about 5% of the normal level, effectively meaning that the first field had "collapsed." Even with these low power levels in the first field of the ESP, the particulate removal efficiencies were still 99.9+ percent and the emission rate was in the range of 0.010 lb/MBtu. The cause of these low power levels in the first field of the ESP is being investigated. These low power levels could be the result of a number of factors, including plate-wire alignment problems as observed in a recent internal inspection.

One surprising result of this ESP testing was that there was no significant improvement in the ESP performance with increasing SCA. For some of these tests, the SCA in the ESP approached 800 ft²/kacfm and the flue gas velocity in the ESP dropped below 2.0 ft/sec and yet the emission rate remained in the same range as in the other tests, i.e., 0.010 lb/MBtu.

Pulse Jet Baghouse Performance

Although not part of the original GSA project, TVA and EPRI had co-founded the installation of a 1-MWe PJBH pilot plant at the CER to be operated in conjunction with the existing GSA demonstration. Later, AirPol and DOE joined in the operation and testing of this PJBH pilot plant program. The PJBH pilot plant, which was started up in late January, 1993, can pull a slipstream of flue gas from either the ESP inlet or outlet, as shown in Figure 1. In the first series of factorial tests, the PJBH pilot plant pulled flue gas from the ESP inlet and thus, treated flue gas with the full particulate loading (3 to 5 gr/acf) from the GSA reactor/cyclone. The inlet flue gas flow rate was about 5,000 acfm, which corresponds to an air-to-cloth ratio (A/C) of 4.0 acfm/ft² in the PJBH. During the second series of factorial tests, the PJBH pilot plant pulled flue gas from the ESP outlet. The same inlet flue gas flow rate was treated (5,000 acfm), but two-thirds of the bags were removed prior to this testing and thus, the A/C for these tests was 12 acfm/ft².

The cleaning of the bags in the PJBH was pressure-drop-initiated during this testing with the cleaning cycle beginning whenever the tubesheet pressure drop reached 6 inches of water. The cleaning continued until the tubesheet pressure drop had declined to about 4-1/2 inches of water. The bags were cleaned by a low-pressure, high-volume, ambient air stream delivered by a rotating manifold.

SO₂ Removal Efficiency for Reactor/Cyclone/PJBH System

The SO₂ removal efficiency in the reactor/cyclone/PJBH system was typically about 3-5 percentage points higher than that achieved in the reactor/cyclone/ESP system at the same test conditions. This higher SO₂ removal efficiency in the PJBH system was not unexpected given the intimate contact between the SO₂-laden flue gas and the solids collected on the outside of the bags as the flue gas passed through the filter cake and the bags before being discharged to the stack. However, it should be noted that most of the SO₂ removal occurred in the reactor/cyclone and the PJBH SO₂ removal efficiency, based on the inlet SO₂ to the reactor, contributed less than 8 percentage points to the overall system SO₂ removal efficiency during this testing.

Particulate Removal

The particulate removal efficiency in the PJBH was 99.9+ percent for all of the tests completed with the full dust loading from the GSA reactor/cyclone. The emission rate for all of these tests was well below the New Source Performance Standards for particulates and was typically in the range of 0.010 lb/MBtu.

AIR TOXICS TEST

A total of six air toxics test segments was completed: four with the GSA reactor operating and two with the GSA system turned off. All of these tests were completed while the boiler was burning the high-sulfur (2.7%), low-chloride Andalex coal and were run at the high flue gas flow rate (20,000 scfm) and the high fly ash loading (2.0 gr/acf) test conditions. The baghouse was operated in alternate arrangements (in parallel and in series with the ESP) during these air toxics tests.

The results of the air toxics testing are being studied. Preliminary information suggests that the GSA process is capable of removing HCl, particulate, and trace metals. The removal rate of HCl across the GSA reactor and cyclone appears to be 100%. Removal rate for trace metals, particulate, and HF also appear to be high during the six test runs.

DEMONSTRATION RUN

The 28-day demonstration run with the GSA operating in conjunction with the ESP only, started on October 25, 1993 and ended on November 24, 1993. This demonstration run began with the boiler burning the high-sulfur (2.7%), low-chloride Andalex coal and test conditions of: 320°F inlet flue gas temperature; 18°F approach-to-saturation temperature; 2.0 gr/acf fly ash loading; 0.12 percent coal chloride level; 20,000 scfm flue gas flow rate; and 30 rpm recycle screw speed. The SO₂ control mode was engaged for this run with an overall system SO₂ removal efficiency set-point of 91 percent. Due to some problems encountered in obtaining high-sulfur coal, a switch was made to burning a higher-sulfur (3.5%) coal for a period of time. The Ca/S ratio averaged 1.40 - 1.45 moles of Ca(OH)₂/mole inlet SO₂ during this demonstration run.

The demonstration run showed that all three of the major objectives were successfully achieved.

- During the entire period of the demonstration run, the overall system SO₂ removal efficiency averaged 90-91 percent, i.e., very close to the set-point. The switch to the higher-sulfur coal demonstrated the flexibility of the GSA system.
- The particulate removal efficiency and emission rate were good averaging 99.9+ percent and below 0.015 lbs/MBtu, respectively.
- The GSA system demonstrated the reliability of this technology by remaining on-line for the entire 28-day period that the boiler was operating.

ECONOMIC EVALUATION

Under the scope of this project, Raytheon Engineers & Constructors prepared an economic evaluation of the GSA FGD process using the same design and economic premises that were used to evaluate about 30-35 other FGD processes for the Electric Power Research Institute. The relative process economics for the GSA system were evaluated for a moderately difficult retrofit to a 300-MW boiler burning a 2.6 percent sulfur coal. The design SO₂ removal efficiency was 90 percent.

The resulting capital cost estimate (in 1990 dollars) is shown in Table 2 together with the estimate for the conventional wet limestone, forced-oxidation (WLFO) scrubbing system. The total capital requirement of \$159/kW for the GSA process is substantially lower than the \$216/kW for the WLFO system. Since the presumed accuracy of these estimates is +/- 10 percent, this lower capital requirement estimate for the GSA FGD process is significant. The substantially lower capital requirement is primarily due to the lower capital costs in the SO₂ absorption area.

Total Capital Investment Comparison (1990 \$, 300-MW, 2.6% S coal)			
		\$/kW	
<u>Area</u>	<u>Description</u>	<u>GSA</u>	<u>WLFO</u>
10	Reagent Feed	26.3	36.7
20	SO ₂ Removal	42.2	71.1
30	Flue Gas Handling	18.9	24.0
60	Solids Handling	4.6	6.7
70	General Support	1.4	1.9
80	Additional Equipment	<u>4.1</u>	<u>4.0</u>
Total Process Capital		97.5	144.4
General Facilities		9.8	14.4
Engineering and Home Office Fees		9.8	14.4
Project Contingency		20.7	25.1
Process Contingency		<u>9.1</u>	<u>3.5</u>
Total Plant Cost		146.9	201.8
Total Cash Expended		143.4	197.0
Allowance for Funds during Construction		<u>8.1</u>	<u>11.1</u>
Total Plant Investment		151.5	208.1
Royalty Allowance		0.5	0.7
Preproduction Costs		5.5	6.7
Inventory Capital		1.9	0.7
Initial Catalysts and Chemicals		<u>0.0</u>	<u>0.0</u>
Total Capital Investment		159.4	216.2

Table 2. Total Capital Investment Comparison

The levelized annual revenue requirements for the two processes (in 1990 dollars) are shown in Table 3. The levelized annual requirement for the GSA process is lower than that for the WLFO system, but the difference is only about 16 percent. Hence, it is not significant compared with the accuracy of the estimate. The principal annual operating cost for the GSA process is the cost of the pebble lime.

LEVELIZED COSTS		
(300-MW, 2.6% S coal, 15-year levelizing)		
	Mills/kWh	
<u>Fixed Costs</u>	<u>GSA</u>	<u>WLFO</u>
Operating Labor	0.52	0.66
Maintenance	1.49	1.74
Administrative and Support Labor	<u>0.34</u>	<u>0.41</u>
	2.35	2.81
<u>Variable Costs</u>		
Raw Material	1.82	0.65
Solids Disposal	0.86	0.57
Water	0.01	-
Steam	-	0.55
Electricity	<u>0.47</u>	<u>1.16</u>
	3.16	2.93
<u>Fixed Charge (Capital)</u>	<u>5.40</u>	<u>7.30</u>
Total	10.91	13.04

Table 3. Levelized Costs

COMMERCIALIZATION

One of the objectives of this demonstration project is for AirPol to establish its capability in designing, fabricating, and constructing the GSA system so that the demonstrated technology can be effectively commercialized for the benefit of the U.S. electric utility and industrial markets. The progress of this demonstration project matches very well with the development of the utility FGD market. The GSA technology is now ready to be commercialized for the industry in order to meet the *Phase II Clean Air Act Amendments compliance requirements*.

During the course of designing the demonstration unit, an effort was made by AirPol to standardize the process design, equipment sizing, and detailed design so that the installation of a commercial unit can be accomplished within a relatively short time frame. An effort was also made during the design phase to achieve simplicity in the equipment design, which later proved to contribute to reduced material and construction costs. With the confidence that the GSA system is capable of achieving the required levels of performance, AirPol has developed a standard design of scale-up units.

Successful effort from the project at the CER has resulted in a commercial application in Ohio. In February 1994, the Ohio Governor announced that the City of Hamilton will receive a \$5 million grant from the Ohio Coal Development Office to install the GSA system to control emissions from a 50 MWe coal-fired boiler at its municipal power plant.

DISCLAIMER

Reference in this report to any specific commercial product, process, or service is to facilitate understanding and does not necessarily imply its endorsement or favoring by either DOE or TVA.

COMMERCIALIZATION OF THE LIFAC SORBENT INJECTION PROCESS IN NORTH AMERICA

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ABSTRACT

This paper discusses the demonstration of LIFAC sorbent injection technology at Richmond Power & Light's (RP&L) Whitewater Valley Station under the auspices of the U.S. Department of Energy's (DOE) Clean Coal Technology (CCT) program.

LIFAC is a unique sorbent injection technology capable of removing 75 to 85 percent of a powerplant's sulfur dioxide emissions using pulverized limestone as a sorbent at calcium to sulfur molar ratios of between 2.0 and 2.5 to 1.

The site of this demonstration is a coal-fired electric utility powerplant located in Richmond, Indiana which is between Indianapolis and Dayton, Ohio. The project is being conducted by LIFAC North America, a partnership of Tampella Power Corp. and ICF Kaiser Engineers, Inc., in cooperation with DOE, RP&L, and several other organizations including the Electric Power Research Institute (EPRI), the State of Indiana, and Black Beauty Coal Company.

INTRODUCTION

The Clean Coal Technology Program (CCT) has been recognized in the National Energy Strategy as a major initiative whereby coal will be able to reach its full potential as a source of energy for the nation and the international marketplace. Attainment of this goal depends upon the development of highly efficient, environmentally sound, competitive coal utilization technologies responsive to diverse energy markets and varied consumer needs. The CCT Program is an effort jointly funded by government and industry whereby the most promising of the advanced coal-based technologies are being moved into the marketplace through demonstration. The CCT Program is being implemented through a total of five competitive solicitations. This paper discusses the LIFAC sorbent injection technology which was selected in the third round of CCT solicitations.

LIFAC North America, a partnership of Tampella Power Corp. and ICF Kaiser Engineers, Inc. have demonstrated the LIFAC flue gas desulfurization technology developed by Tampella Power. This technology provides sulfur dioxide emission control for coal fired powerplants, especially existing facilities with tight space limitations. Sulfur dioxide emissions are reduced over 75% by using limestone as a sorbent. The limestone is injected into the upper regions of a furnace, where calcining to lime and partial absorption of SO_2 occur. Subsequently, the combustion gas is passed through a unique piece of equipment known as the LIFAC activation reactor. This is a vertical elongation of ductwork between the air preheater and ESP where the combustion gas is humidified and SO_2 absorption is completed.

The LIFAC technology is being demonstrated at Whitewater Valley Unit No. 2, a 60 MWe coal-fired powerplant owned and operated by Richmond Power and Light and located in Richmond, Indiana. The Whitewater plant consumes high-sulfur coals with sulfur contents ranging from 2.0 - 2.9 percent.

The project has a total budget of 21.4 million dollars and a duration of 48 months from the preliminary design phase through the testing program.

The sponsors of this project believe that LIFAC has the potential to be a new and important SO₂ control option for U.S. utilities subject to the Clean Air Act's acid rain regulations. To be considered as a commercially feasible option in this particular emissions control market, LIFAC must demonstrate a high SO₂ removal rate while remaining competitive with other options on a cost per ton of SO₂ removed basis. To this end, the project sponsors designed the demonstration with four goals in mind:

- **Sustained High SO₂ Removal Rate** - Incorporated into the test plan were numerous periods of testing which were intended to demonstrate LIFAC's SO₂ removal efficiency and reliability characteristics under several operating conditions.
- **Cost** - LIFAC must compete with available SO₂ control options having both low and high capital costs, including conventional sorbent injection and highly efficient wet scrubbing. This project demonstrated LIFAC's competitiveness on a cost per ton of SO₂ removed basis with these currently available alternatives.
- **Retrofit Adaptability** - The host site chosen required a retrofit with tight construction conditions, proving LIFAC's ability to be installed where other technologies might not be possible. Construction also demonstrated LIFAC's ability to be built and brought on-line with zero plant down time other than scheduled outages.
- **System Compatibility** - A major concern of utilities is the degree of compatibility of SO₂ removal systems with their existing operations. This demonstration proved that LIFAC has minimal impact on the host site's boiler and associated subsystems.

LIFAC PROCESS HISTORY AND DESCRIPTION

In 1983, Finland enacted acid rain legislation which applied limits on SO₂ emissions sufficient to require that flue gas desulfurization systems have the capability of removing nearly 80 percent of the sulfur dioxide from the flue gas. Therefore, Tampella Power began developing an economical, alternative sorbent injection system. Process development first involved laboratory and pilot-plant tests, then full-scale tests of sorbent injection of limestone. Subsequent research and development by Tampella led to the addition of a humidification section after the furnace which became known as the LIFAC process.

In 1986, the first major full-scale test was performed at Imatran Voima's Inkoo powerplant in Finland using a 70 MW side-stream from a 250 megawatt boiler burning 1.5 percent sulfur coal. A second LIFAC activation reactor was constructed to handle an additional 125 megawatt side-stream. These initial demonstration installations were capable of achieving removal rates of 70 to 80 percent while using Ca/S molar ratios of between 2 and 2.5 to 1.

In 1988 the first tests with high-sulfur U.S. coals were performed at Tampella's pilot plant in Finland. A Pittsburgh No. 8 Seam coal containing 3 percent sulfur was evaluated and an SO₂ removal rate of over 70 percent was achieved at a Ca/S molar ratio of 2 to 1.

Currently there are 10 full size LIFAC units in operation or under construction in 5 countries; the United States, Canada, China, Russia and Finland.

LIFAC PROCESS DESCRIPTION

The LIFAC system combines conventional limestone injection into the upper furnace region with a post-furnace humidification reactor located between the air preheater and the ESP. The process produces a dry, stable waste product that is removed from both the bottom of the humidification reactor and the ESP.

Finely pulverized limestone is pneumatically conveyed and injected into the upper region of the furnace where temperatures are approximately 1800 to 2200 degrees Fahrenheit. At these temperatures the limestone (CaCO₃) calcines to form calcium oxide (CaO) which readily reacts with the SO₂ to form calcium sulfate (CaSO₄). Most of the sulfur trioxide (SO₃) reacts with the CaO to form CaSO₄.

Approximately 25 percent of the sulfur dioxide removal occurs in the furnace with the remaining 75 percent and the unreacted lime passing through the air preheater to the humidification reactor. There the flue gas is sprayed with atomized water which hydrates the unreacted lime to form Ca(OH)₂. The hydrated lime more readily reacts with the sulfur dioxide and forms calcium sulfite (CaSO₃). A combination of the proper water droplet size

and residence time allows for effective hydration of the lime and complete water evaporation to create a dry reactor bottom product.

After exiting the humidification reactor, the flue gas is reheated before entering the ESP. The humidification and lower gas temperature enhance the efficiency of the ESP. Approximately 40 percent of the LIFAC by-product is collected by the humidification reactor while the remaining 60 percent by the ESP. Both the reactor and ESP ash may be recycled to a point ahead of the reactor to improve sorbent utilization and SO₂ removal efficiency of the system. A diagram of the LIFAC process is shown in Figure 1.

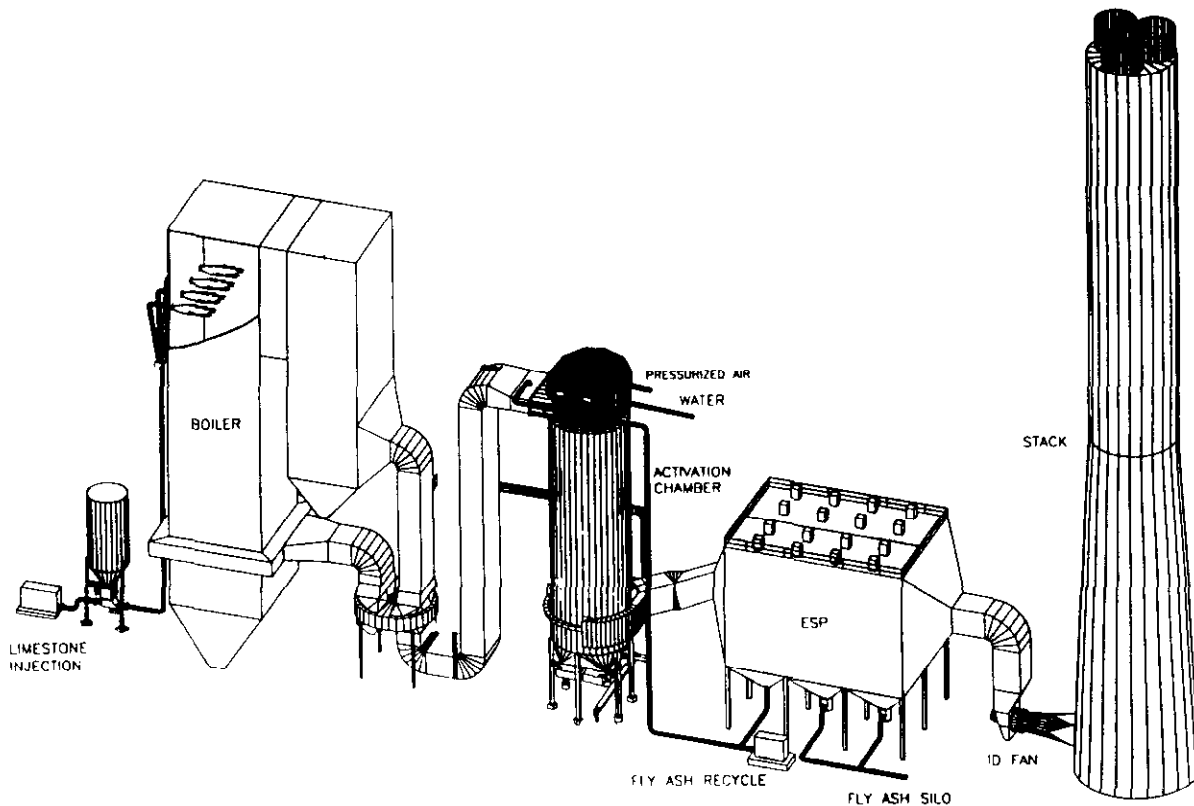


Figure 1 The LIFAC Dry Flue Gas Desulfurization Process.

PROCESS ADVANTAGES

LIFAC is similar to other sorbent injection technologies but has unique advantages with its use of a patented vertical humidification reactor. LIFAC's sulfur dioxide removal efficiency is not as high as traditional wet flue gas desulfurization systems. However, its cost, simplicity of design, construction, and operation offer other advantages over these alternative systems. In particular the advantages of the LIFAC system are:

- **High SO₂ removal rates** - Currently available sorbent injection systems have been unable to sustain high SO₂ removal rates with any consistency. LIFAC has proven its ability to achieve and sustain high SO₂ removal rates above 70 percent over long operating periods.
- **By-products** - Wet lime and limestone scrubbing systems create a wet by-product that must be further treated before disposal. LIFAC produces a dry, solid by-product containing calcium sulfate, calcium sulfite, and fly ash. This waste is easily disposed of under U.S. regulatory requirements and is expected to have commercial applications in the cement and agriculture industries.
- **Compatibility and Adaptability** - LIFAC has minimal impact on the host's site and systems, primarily the boiler, ESP, and ID fan. In addition, LIFAC requires little space and few utilities and therefore is easily installed even in small or cramped powerplant sites.

CONSTRUCTION AND SYSTEMS INTEGRATION

Construction of the LIFAC system in Richmond occurred in two phases over a period of one and a half years. The first phase of construction was completed during a routine plant outage in March of 1991. This period was utilized to install tie-ins to the host site's existing systems.

Ductwork and three dampers were installed between the air preheater and ESP to allow flue gas flow to the LIFAC activation reactor. Tie-ins were also made to the powerplant's medium pressure steam, condensate, and river-water supplies. The steam is employed to reheat the flue gas exiting the LIFAC reactor. Water is utilized for flue gas humidification within the reactor.

The second phase of construction began in the Fall of 1991 with the driving of reactor piling and the installation of underground conduit runs. Work continued through the Summer of 1992 with no need for plant downtime, other than normally scheduled outages. During this time the limestone storage area was completed and the injection system was installed on Unit No. 2. Twelve Injection ports were installed in the boiler walls, six at the boiler nose elevation and six nearly 10 feet above the nose elevation. The activation reactor was constructed and then tested with cold air during a scheduled Unit No. 2 outage, then with hot flue gas during a low electricity demand period. Other powerplant tie-ins such as the steam and condensate system were also tested during low demand periods in the evenings or on weekends.

SCHEDULE

The current schedule for the LIFAC demonstration program extends over a four year period beginning with preliminary design in August, 1990.

All construction work was completed at the beginning of August of 1992. Equipment check-out was performed in July and August and the first limestone delivery was received in early September of 1992. Initial tests with limestone injection into the boiler along with post-furnace humidification were conducted from October through December, 1992. All test work was completed in the summer of 1994. Project reporting activities will continue through the end of 1994.

TEST PLAN

The process evaluation test plan is composed of five distinct phases of testing, each having its own objective. The test program was implemented in conjunction with periodic ESP evaluation and environmental monitoring. Environmental monitoring included coal, ash, water, and gas sampling from strategic locations around the plant. The tests incorporated into the LIFAC demonstration were:

- **Baseline Tests** - Baseline measurements were taken to characterize the operation of the host boiler and associated subsystems prior to LIFAC operations.

- **Parametric Tests** - Parametric tests were designed to evaluate the many possible combinations of LIFAC process parameters and their effects on SO₂ removal. The variables evaluated included: boiler load, coal sulfur content, limestone quality, limestone injection nozzle setting, Ca/S molar ratio, water droplet size, humidification nozzle arrangement, approach to saturation temperature, and ESP ash recycling rate. At the conclusion of this phase, the ideal combination of parameters were chosen and implemented for the remainder of the test program.
- **Optimization Tests** - Optimization tests were performed after parametric testing to evaluate the reliability and operability of the LIFAC process over short, continuous operation periods.
- **Long-term Tests** - Long-term tests were performed to demonstrate LIFAC's performance under commercial operation conditions. Extensive ESP evaluations were performed during parametric and long-term test periods. The LIFAC system was in continuous operation for several weeks using the powerplant's baseline coal, high calcium limestone, and optimum process variables. Operational costs were determined by measuring mass flow rates and energy consumption. Operability of the process was evaluated by studying all LIFAC process parameters and their impacts on powerplant operation.
- **Post-LIFAC Tests** - The final phase of testing was composed of repeating the baseline tests to gather information on the condition of the boiler and its associated subsystems. Comparisons were made to the original baseline data and any changes caused by the LIFAC system were identified. Post-LIFAC and baseline test results are also compared with long-term data in order to evaluate the host facility's operation with and without LIFAC engaged.

RESULTS

Parametric - The numerous LIFAC process values and their effects on sulfur removal efficiency were evaluated during parametric testing. Some results are inconsistent with others due to differing test durations or unscheduled interruptions. Testing a single parameter would last from one to several hours and was repeated until accurate results were

achieved. Four major parameters which had the greatest influence on sulfur removal efficiency were; Limestone quality, Ca/S molar ratio, Reactor bottom temperature (Approach to saturation), and ESP ash recycling rate.

Total SO₂ capture was about 15 percentage points better when injecting fine limestone (80% minus 325 mesh) than it was with coarse limestone (80% minus 200 mesh). Figure 2 shows the effects of grind size on SO₂ capture. While injecting fine limestone the soot blowing frequency needed to be increased from 6 to 4.5 hour cycling periods. Whereas, coarse quality limestone did not effect soot blowing, but was found to be more abrasive on the feed and transport hoses.

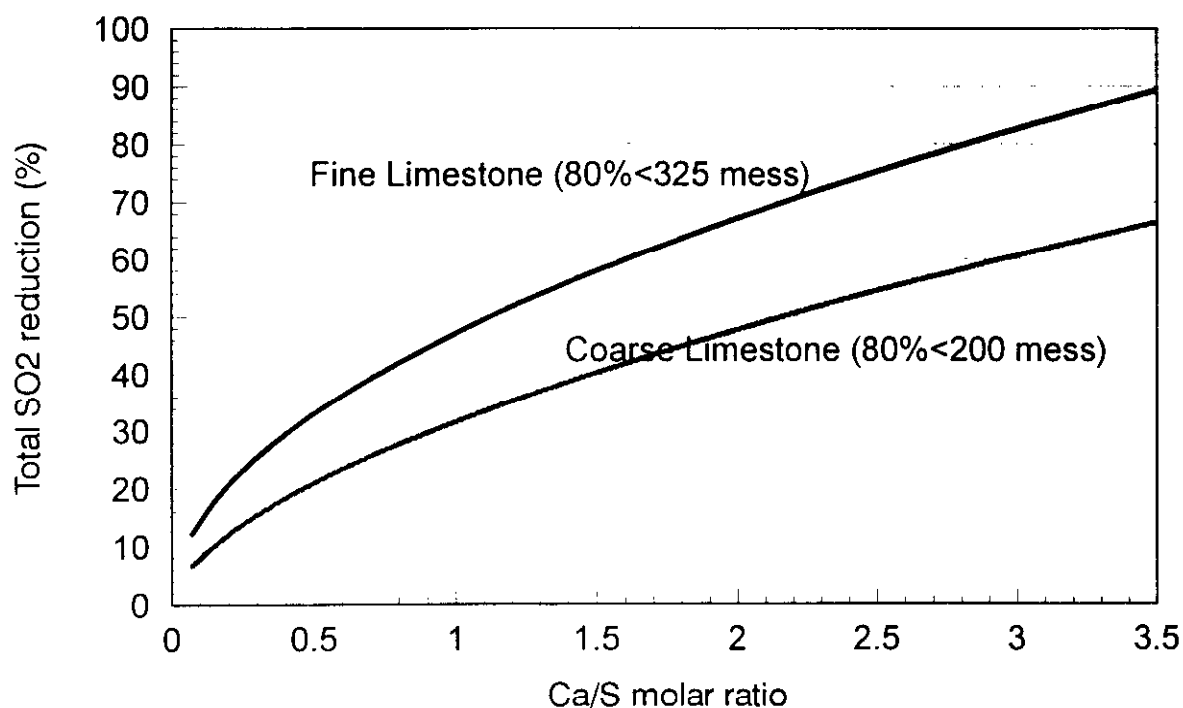


Figure 2 The Effect of Limestone Grind Size on SO₂ Capture.

Ca/S molar ratios between 0.5 to 2.5 were tested and results are shown in Figure 3. As the Ca/S molar ratio is increased, sulfur removal efficiency improves as expected. The majority of the tests had been conducted at 2.0.

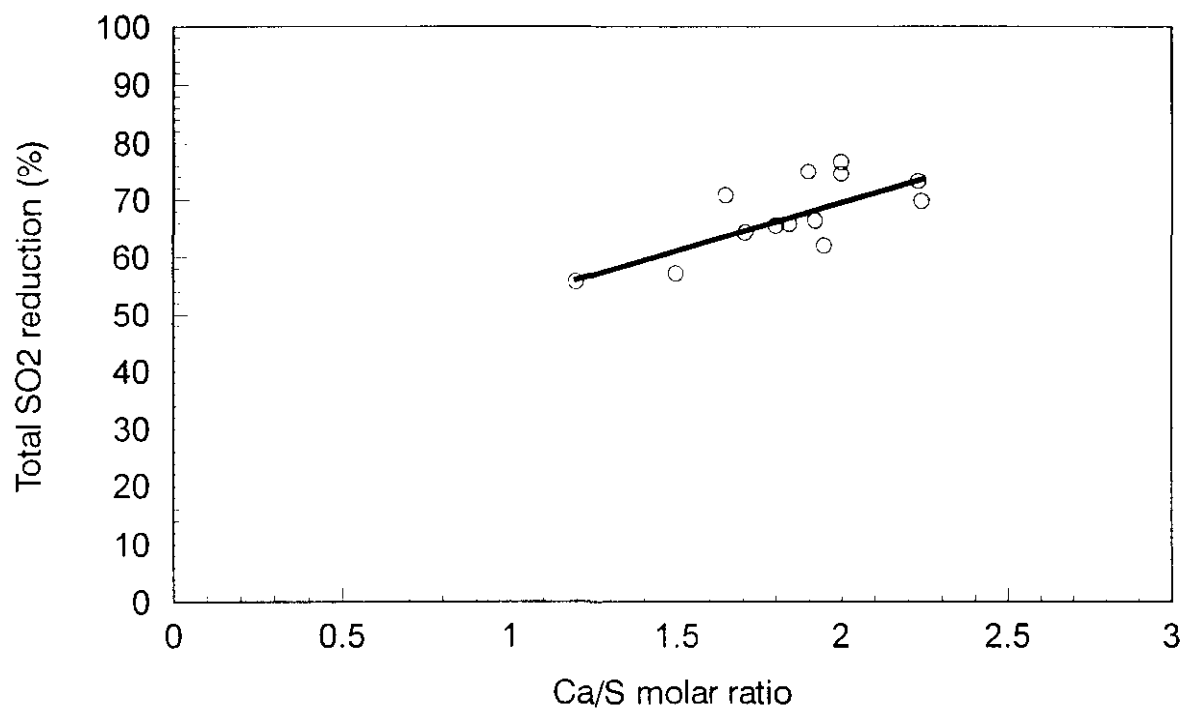


Figure 3 Ca/S Molar Ratio Effect on Sulfur Removal Efficiency.

Most tests were performed with the lowest possible reactor bottom temperature (anywhere between 5 and 10°F above the flue gas saturation temperature). Higher temperatures resulted in poor sulfur capture.

ESP ash containing unspent sorbent and fly ash was recycled from the ESP hoppers back into the reactor inlet ductwork. Ash recycling is essential for efficient SO₂ capture. The large quantity of ash removed from the LIFAC reactor bottom, and the small size of the ESP hoppers, limited the ESP ash recycling rate. As a result, the amount of material recycled from the ESP was approximately 70 percent less than had been anticipated. However, this low recycling rate contributed an additional 15 percentage points to total SO₂ capture as shown in Figure 4. During a brief test it was found that increasing the recycle rate by 50 percent resulted in a 5 percentage point increase in SO₂ removal efficiency.

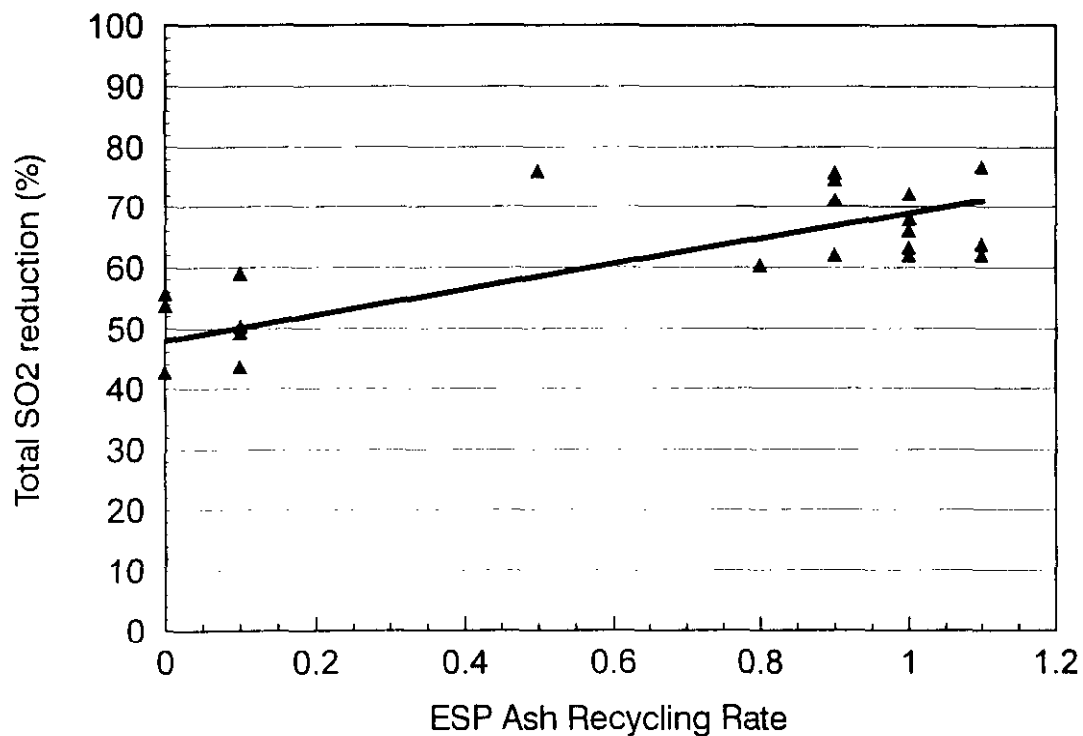


Figure 4 ESP Recycling Rate vs. Total Sulfur Dioxide Removal

It is anticipated that if the reactor bottom ash is recycled along with ESP ash, while sustaining a reactor temperature of 5°F above saturation temperature, a SO₂ reduction of 85 percent could be maintained.

Long-term - Optimum process parameters were implemented in order to evaluate long-term operation efficiency, operability, and economy of the process.

The boiler was operated at an average load of 60 MW during long-term testing. However, the boiler fluctuated according to power demand at night and on weekends. The LIFAC process automatically adjusts to boiler load changes. A Ca/S ratio of 2.0 was selected to attain SO₂ reductions above 70 percent. Reactor bottom temperature was about 5°F higher than optimum. This higher temperature was maintained to avoid ash buildup on the steam reheaters located in the exiting ductwork. A lower temperature would have improved sulfur removal efficiency. Atomized water droplet size was smaller than optimum for the same reason.

The process did achieve over 70 percent SO₂ capture, even though operating conditions were not quite optimum. Figure 5 shows typical SO₂ reduction, Ca/S molar ratio, and boiler load trending for a one week period.

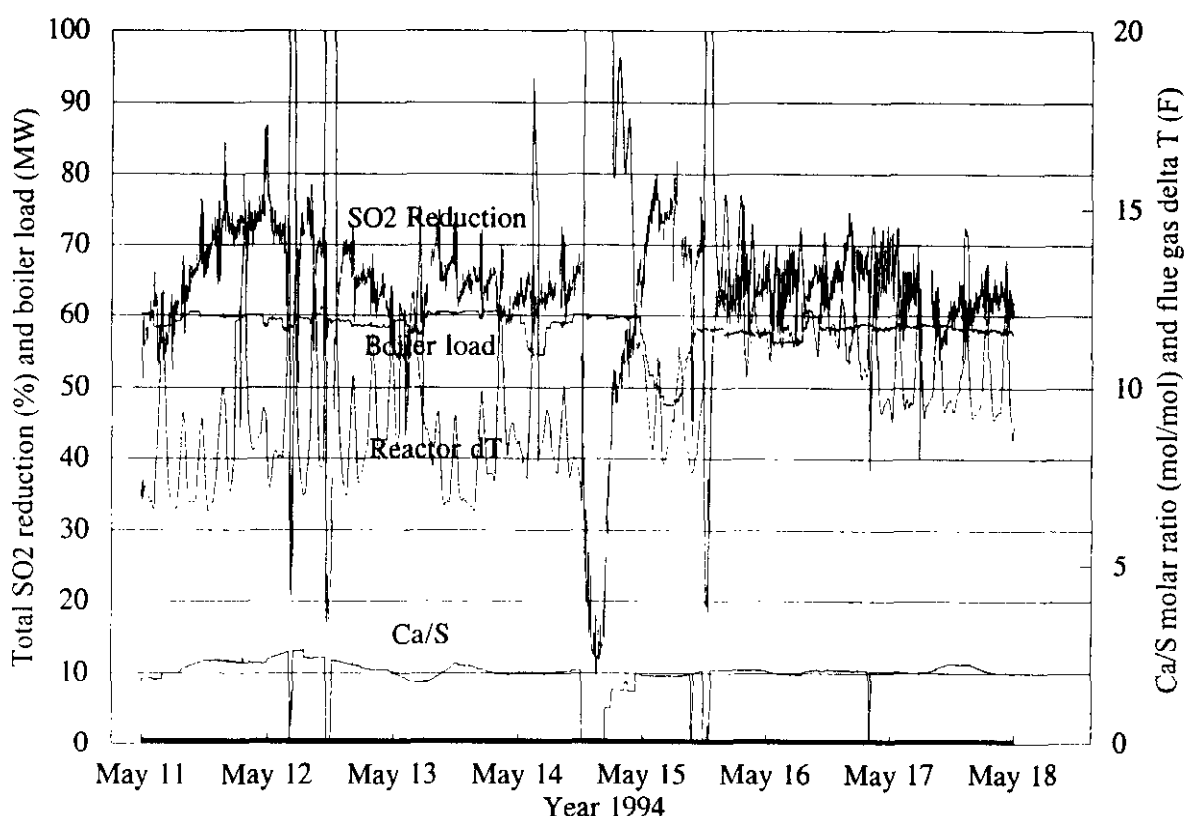


Figure 5 One Week Trend of Results During Long-term Testing.

Impact on RP&L - Limestone flow to the furnace was relatively high due to the high sulfur content (2.25%) of the coal and a Ca/S ratio of 2.0. Soot blowing frequency needed to be increased from 6 to 4.5 hour cycles with the finer grind limestone normally used.

The amount of boiler bottom ash increased slightly. There was no negative impact on the powerplant's bottom and fly ash removal systems. ESP and LIFAC fly ash were readily disposed of at the same local landfill.

During startup and shutdown of the LIFAC process, the ESP clamping force was degraded due to lower ash resistivities caused by the low temperature, high humidity flue gas generated by LIFAC. During a scheduled boiler outage, modifications were made to reheat and improve flue gas distribution through the ESP. These improvements shortened the transient period experienced by the ESP. Stack opacity was low (about 10%) and ESP efficiency was high (99.2%) during normal LIFAC operation, after transient conditions had passed. ESP efficiency is approximately 98.7%, with opacity levels ranging from 5% to 10%, without LIFAC in operation.

A variable frequency drive (VFD) was installed with LIFAC to control ID fan speed and furnace draft. Unfortunately, the VFD was non-operational for much of the time and the ID fan's inlet damper was used for furnace draft control. Without the LIFAC process in operation, the 60 MW unit can operate at a peak 65 MW load. The boiler could have operated at higher loads during LIFAC operation if the VFD were operational.

Operability - The LIFAC system proved to be highly operable since it has few moving parts and is simple to operate. The process can easily be shutdown for maintenance and restarted without any special action required.

The process is automated by a Programmable Logic System. This system regulates process control loops, interlocking, startups, shutdowns, and data collection. The entire LIFAC process was easily managed via two IBM personal computers located in the RP&L control room.

Throughout the demonstration, LIFAC was operated from a few days to several weeks at a time. The total duration of the project was 2,800 hours of operation, over a two year period.

An unscheduled shutdown of the process occurred during long-term testing in May, 1994. Problems with the limestone feeding unit, an I/O panel, and humidification nozzles needed to be corrected before resuming operations. All repairs were minor.

The matrix of steam reheat coils in the exiting reactor ductwork became plugged due to low reactor bottom temperatures. There is no soot blowing system situated near these coils and they needed to be cleaned periodically during downtime. The steam reheat coils will eventually be replaced with a hot flue gas reheat system.

Economy - The capital cost of a LIFAC installation is lower than both spray driers and wet scrubbers. Installation cost is between \$50 and \$100 per kilowatt, depending on the unit size and the quantity of reactors needed. A wet scrubber is more economical for large boilers since one wet scrubber can treat large volumes of flue gas. Table 6 provides a breakdown of the installation costs of the two most recent LIFAC installations along with an estimated cost of a wet scrubbing unit. The Shand station has a 300 MW boiler that was fitted with only one 150 MW LIFAC activation reactor. The cost of a 300 MW system was also presented to Shand, had it been necessary for compliance purposes.

Crushed limestone accounts for approximately one-half of LIFAC's operation costs. Other major operating costs include: waste disposal, auxiliary power, labor, and maintenance.

Assuming that SO_2 capture is 75 percent, the Ca/S molar ratio is 2.0, and the limestone has 95 percent CaCO_3 , LIFAC requires 4.3 tons of limestone to remove 1 ton of sulfur dioxide. If the cost of limestone is \$15 per ton then it costs \$65 per ton of SO_2 removed.

		Shand Station		RP & L
	Wet Scrubber (300 MW)	Two LIFAC Reactors (300 MW)	One LIFAC Reactor (150 MW)	One LIFAC Reactor (65 MW)
CAPITAL COSTS (\$ Millions)				
Reactor and Auxiliaries	61.6	16.0	8.7	4.5
Sorbent Injection	incl.	0.7	0.7	0.4
Sorbent Processing	incl.	0.0	0.0	0.0
Delay ESP Duct Erection	incl.	0.4	0.4	0.0
Electrical Installation / Controls	incl.	1.1	0.7	1.1
Misc. Mechanical Installation	incl.	0.2	0.1	0.1
Air Compressor	incl.	0.5	0.2	incl.
Foundations	incl.	0.6	0.3	0.3
Ash System	incl.	0.2	0.2	incl.
Total	61.6	19.7	11.4	6.4
Cost (\$/kW)	\$205	\$66	\$76	\$99

Table 6 Comparison of FGD Installation Costs

The waste produced by LIFAC is a mixture of fly ash and calcium compounds. The quantity of ash by-product removed is approximately equal to the amount of limestone injected.

Auxiliary power consumption is nearly 0.6 percent of Unit No. 2's net capacity. The air compressors and blowers consume most of this portion of the power.

Additional energy is required to reheat the exiting flue gas nearly 45°F before it enters the ESP. This energy amounts to approximately 0.5 percent of the boiler's thermal energy. The steam reheaters draw energy from a 230 psig medium pressure steam source, while a small gas reheat duct bypasses 3 to 4 percent of 850°F flue gas from slightly above the economizer.

COMMERCIALIZATION

Operation test results are now available from the first U.S. LIFAC installation and two Canadian LIFAC installations. All three of these full-size units were built for continuous, commercial operation.

The LIFAC system at Richmond Power and Light is the first to be applied with high sulfur coal. The sulfur content of the coal burned at RP&L ranges from 2.0 to 2.9%. Whereas, the other LIFAC installations treat powerplants which consume bituminous and lignite coals having lower sulfur contents (0.6 to 1.5%).

The unit at RP&L is currently the only U.S. LIFAC installation. This demonstration project, along with other installations around the globe, has proven that the LIFAC process is an economical alternative for coal fired plants in the United States.

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CT-121 SCRUBBER DEMONSTRATION MID-PROJECT PERFORMANCE RESULTS

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INTRODUCTION

The Chiyoda CT-121 Innovative Clean Coal Technology (ICCT) Project is a \$44 million, Round II project co-funded by the Southern electric system, the Department of Energy (DOE), and the Electric Power Research Institute (EPRI). The project is located at Georgia Power's Plant Yates Unit 1, about 40 miles southwest of Atlanta, Georgia.

The demonstration project involves the retrofit construction and operation of a CT-121 wet-limestone scrubber on a 100 MWe coal-fired boiler with an existing electrostatic precipitator (ESP). The CT-121 process differs from conventional wet-limestone, forced-oxidized, flue gas desulfurization (FGD) spray tower technology by using a single absorber module, called a jet bubbling reactor (JBR), in lieu of the more typical spray tower - reaction tank arrangement. The JBR is the centerpiece of the CT-121 process and is made completely of

fiberglass reinforced plastics (FRP). In the JBR, all the chemical reactions necessary for the removal of SO₂ and subsequent precipitation of the gypsum by-product occur.

The demonstration has two operational phases. The first, between January 1993 and February 1994, was conducted with the pre-existing ESP in service. The second phase, which began in March 1994, is a repeat of the first phase testing, only with the ESP deenergized to allow evaluation of the scrubber's performance under high particulate loading conditions. These phases are further divided into distinct test periods which include parametric testing, long-term load-following evaluation, a high-performance test, and a determination of the impact on scrubber performance made by varying coal and limestone sources.

Preliminary testing of the CT-121 process at Plant Yates has produced excellent performance results. The process has proven itself capable of easily exceeding its design SO₂ removal efficiency performance specification of 90%, both with and without the ESP in service. The process has also achieved SO₂ removal efficiencies as high as 98% without the use of performance-enhancing additives such as organic acids. Particulate measurements performed with the ESP deenergized have established the capability of the CT-121 process to remove over 99% of the boiler's particulate emissions at 100% boiler load. Long-term testing has shown the process to be very robust, and the process' reliability has been over 98% since the beginning of operation in October 1992. This paper will focus on the most recent test results of the demonstration, specifically those from the High Sulfur and High Particulate Parametric test periods.

FACILITY DESCRIPTION

The equipment comprising the demonstration facility can be divided into five major systems: boiler/ESP; CT-121 scrubber/wet chimney; limestone preparation circuit; by-product gypsum stacking area; and process control system.

Plant Yates' Unit 1, which has a rated capacity of 100 MWe, is the source of flue gas for the CT-121 process. All of the flue gas from this unit is treated by the CT-121 wet FGD process

with no provision for flue gas bypass. During the low fly-ash phase of parametric testing, the existing ESP for Unit 1 was used for particulate control. The design efficiency for this ESP is 98%.

A simplified process flow diagram for the CT-121 process is presented in Figure 1. The central feature of the process is a unique absorber design, called a Jet Bubbling Reactor, which combines SO_2 absorption, sulfite oxidation, neutralization, and gypsum crystallization in one reaction vessel. This design significantly reduces the potential for gypsum scaling, a problem that frequently occurs in natural-oxidation FGD systems. Since much of the crystal attrition and secondary nucleation associated with the large centrifugal pumps in conventional FGD systems is also eliminated in the CT-121 design, large, easily dewatered gypsum crystals can be produced.

In the Yates application, the flue gas enters the inlet gas cooling section after the induced draft (I.D.) fan. Here the flue gas is cooled and saturated with a mixture of pond water and JBR slurry. From the gas cooling section, the flue gas enters the JBR. The gas enters an enclosed plenum chamber formed by an upper deck plate and a lower deck plate. Sparger tube openings in the lower deck plate force the inlet flue gas into the slurry contained in the jet bubbling (froth) zone of the JBR vessel. After bubbling through the slurry, the gas flows upward through gas risers which pass through both the lower and upper deck plates. Because of the torturous path the flue gas takes through the slurry, most of the particulate is removed from the flue gas, even with the ESP out of service. Entrained liquor in the gas disengages in a second plenum above the upper deck plate, and the cleaned gas passes to the 2-stage, chevron-style, horizontal-flow mist eliminator.

After leaving the mist eliminator, the clean gas exits the system through a wet chimney. Since the gas enters the chimney saturated with water, any heat loss in the chimney will result in gas cooling and water condensation. Condensate in the chimney is collected by a system of internal "gutters" and is returned to the JBR.

A closed-circuit wet ball mill limestone preparation system is used to grind raw limestone. The particle size of the ground limestone is small enough to ensure that the amount of unreacted limestone in the JBR can be kept to a minimum. The baseline particle size used is 90% passing a #200 mesh screen.

The slurry from the JBR is pumped to a gypsum slurry transfer tank and then pumped to a lined gypsum stacking area for dewatering and storage. The stacking technique involves filling a diked area with slurry. The filled area is then partially excavated to increase the height of the containment dikes. The process of sedimentation, excavation, and raising perimeter dikes continues on a regular basis during the active life of the stack. Process water is decanted, stored in a surge pond, and then returned to the process.

During normal operation of the FGD system, the amount of SO₂ removed from the flue gas is controlled by varying the JBR pressure drop (ΔP) across the upper and lower decks. The ΔP is adjusted by varying the JBR liquid level. The ΔP due to hydrostatic immersion of the sparger tubes usually accounts for at least 90% JBR ΔP . Higher liquid levels result in increased SO₂ removal because of increased contact between the incoming flue gas and the scrubbing slurry. The pH can also be varied to affect SO₂ removal with higher pH resulting in increased removal. Boiler unit load and flue gas SO₂ concentration, determined by system electrical demand and coal sulfur content, respectively, also affect removal efficiency.

One of the most unique aspects of the CT-121 installation at Plant Yates, is the wide use of fiberglass reinforced plastics in several of the vessels. Two of the vessels (the JBR and the limestone slurry storage tank) were constructed on site since the large size precluded shipment. A distinctive advantage of the FRP construction was that it eliminated the need for a flue gas prescrubber to remove chlorides because the corrosion resistance properties of the fiberglass are superior to those of alloys. This represented a large capital cost savings to the project.

CT-121 PERFORMANCE

It has already been demonstrated and reported [1] that the Yates CT-121 process performed well under typical operating conditions (i.e., 2.5% sulfur coal, ESP in service). During more recent testing, the process was stressed by operation beyond its design coal sulfur content basis (by burning 4.3% sulfur coal) and with high particulate loading, and still recorded excellent performance. An alternate limestone source was also used to demonstrate operational flexibility, and high SO₂ removal efficiency testing was conducted to further evaluate the process' capabilities.

Alternate Limestone Sources

Alternate Limestone testing was conducted to compare the performance of the process using a limestone from a different quarry than the limestone that was previously used. The Alternate Limestone tests were also used to validate the results of a bench-scale limestone evaluation study, which established that limestone selection could have a significant impact on gypsum crystal morphology and dewatering characteristics. The bench-scale test results indicated that changing the limestone source might improve the solids dewatering properties by causing an increase in the size of the gypsum particles. The specific mechanism of this effect is not known, but evidence suggests that it may be linked to the inerts content, inerts composition, and/or the soluble iron in the limestone.

The key to improving solids dewatering properties lies in improving the crystal size and morphology, or shape. In general, larger, regularly shaped crystals dewater better than smaller, irregularly shaped crystals. Figure 2 shows a comparison of the particle size distribution (PSD) of gypsum byproduct solids generated using the original limestone reagent, with solids generated using the new limestone, at similar process operating conditions. Note the increase in mean particle size (from 32 μ to 42 μ) resulting from the switch in limestone sources, and the reduction in the fines (less than 10 μ) content of the byproduct. These results served to validate those from the bench-scale study and established the bench-scale screening procedure as a viable way to evaluate limestones for use in forced-oxidation wet-limestone FGD systems.

Higher Sulfur Coal

To evaluate the operability and performance of the Yates CT-121 process with alternate sources of fuel supplied to the Unit 1 boiler, higher sulfur coal, averaging 4.3% sulfur, was procured on the spot market. This new coal's sulfur content was 170% higher than the typical coal sulfur content - 2.5%. The only required modifications to the process were installation of additional oxidation air blowers (to ensure all the sorbed SO₂ could be readily oxidized to SO₄), and larger motors were mated to the limestone slurry reagent pumps (to allow enough reagent to be delivered to the process to maintain process pH in the desired range).

Even though the Yates CT-121 process was operated at 170% of its design conditions with respect to SO₂ pickup, the performance of the scrubber was excellent. SO₂ removal efficiency ranged from 79% to 97% over a range of control setpoints, and inlet SO₂ concentrations varied from 3380 to 3820 ppm (at 3% O₂, dry basis). Note that only a modest decrease in performance (compared to results from 2.5% sulfur coal testing) was observed despite operating far outside the process design constraints, as shown in Figure 3. The higher SO₂ absorption rate associated with the increase in inlet SO₂ concentration also resulted in a decrease in JBR solids residence time from 45 hours to 26 hours. This lower residence time resulted in less gypsum crystal formation time and slightly lower mean particle size (from 42 μ to 38 μ). Despite the smaller mean particle size, no decrease in solids dewatering performance was noted.

Particulate Removal

Particulate testing was performed concurrently with the high-particulate (ESP deenergized) parametric testing. Sampling was conducted at both the inlet duct and the outlet wet chimney to quantify the performance of the JBR in the removal of particulate matter at several different inlet particulate loading conditions. With the ESP fully detuned, the scrubber inlet particulate loading averaged 5.3 lb/MBtu. At various conditions of load and JBR ΔP , the outlet mass loading averaged 0.049 lb/MBtu, well below the state permit limit of 0.24 lb/MBtu. These data represented a 99.1% particulate removal efficiency across the scrubber. Previous particulate testing (with the ESP in service) indicated that 67% of the outlet mass loading was sulfate carryover (i.e., only 33% was ash). It is believed that a portion of the outlet loading from the

high particulate testing is also a result of carryover, but at the time of this writing, complete quantitative analyses of the outlet particulate samples were not yet available.

High Removal Efficiency

High SO₂ removal efficiency testing was conducted to determine the maximum removal efficiency that could be achieved within normal process operating conditions. The maximum SO₂ removal efficiency achieved during this testing was 97.8% at full load (100 MWe), 18 inches WC ΔP, a JBR pH of 4.8, and 2200 ppm inlet SO₂ concentration (corrected to 3% O₂). At 50 MWe, SO₂ removal was measured as high as 98.7%. This level of performance is exceptional for wet-FGD systems operating without the use of performance-enhancing additives, such as organic acids.

CONCLUSIONS

The demonstration of the CT-121 scrubber at Georgia Power's Plant Yates has established this technology as an efficient, reliable, flexible means of removing SO₂ from flue gas. The process has exhibited outstanding performance and reliability with different coal sources and limestone reagents, while still easily surpassing the project goal of 90% SO₂ removal efficiency. High efficiency testing established the process' ability to consistently remove in excess of 98% of SO₂ in the flue gas stream at some operating conditions. All, while achieving parasitic power consumption levels of less than 1.8% of maximum capacity (100 MWe).

The recently begun, high particulate test phase has demonstrated the robustness of the process. The CT-121 process has exhibited in excess of 99% particulate removal efficiency with inlet particulate mass loading as high as 1.8 gr/acf without any significant process equipment deterioration.

Since operation began in October, 1992, the Yates CT-121 demonstration has attracted a considerable amount of attention. The plant and scrubber have received environmental awards from the Georgia Environmental Protection Division and the Air and Waste Management

Association, as well as the prestigious Power Magazine 1994 Power Plant Award[2]. These successes have catalyzed the signing of an agreement by a Canadian facility for the purchase of a 350 MWe CT-121 scrubber. Additionally, many other interested parties have visited the Yates scrubber to assist them narrowing their selection of technology for Clean Air Act Title IV compliance. The efficiency and commercial viability of the CT-121 process should make it a strong contender in potential Phase II compliance strategies.

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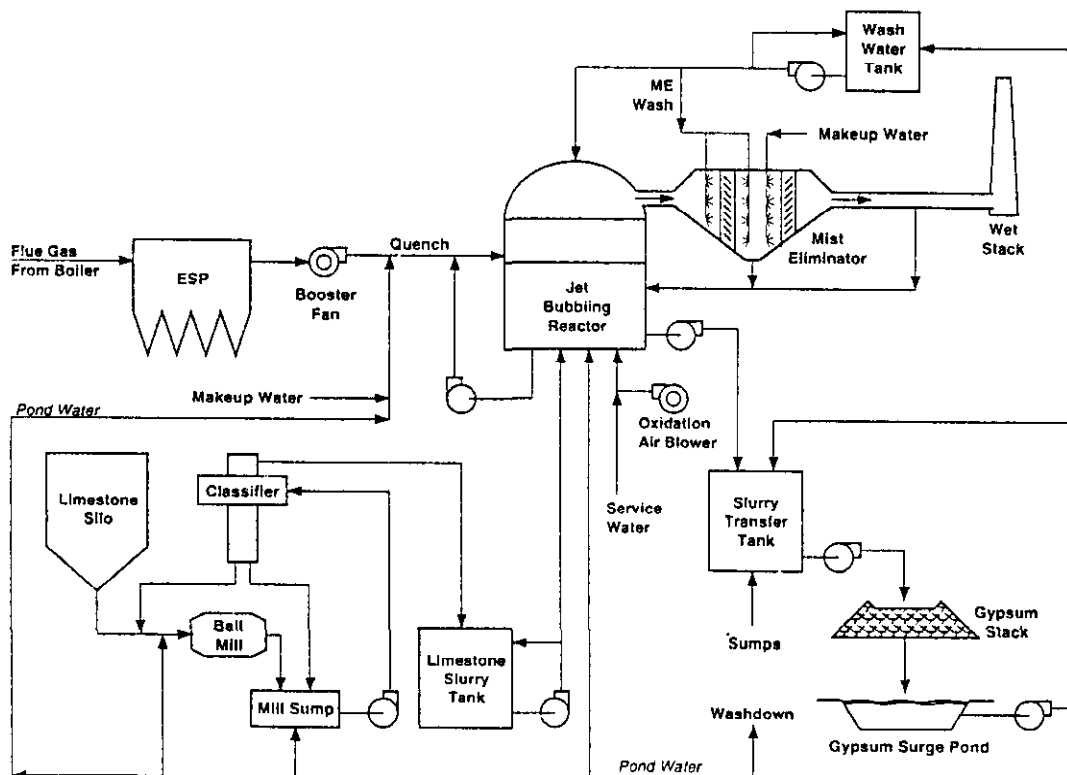


Figure 1. Yates CT-121 Simplified Process Flow Diagram

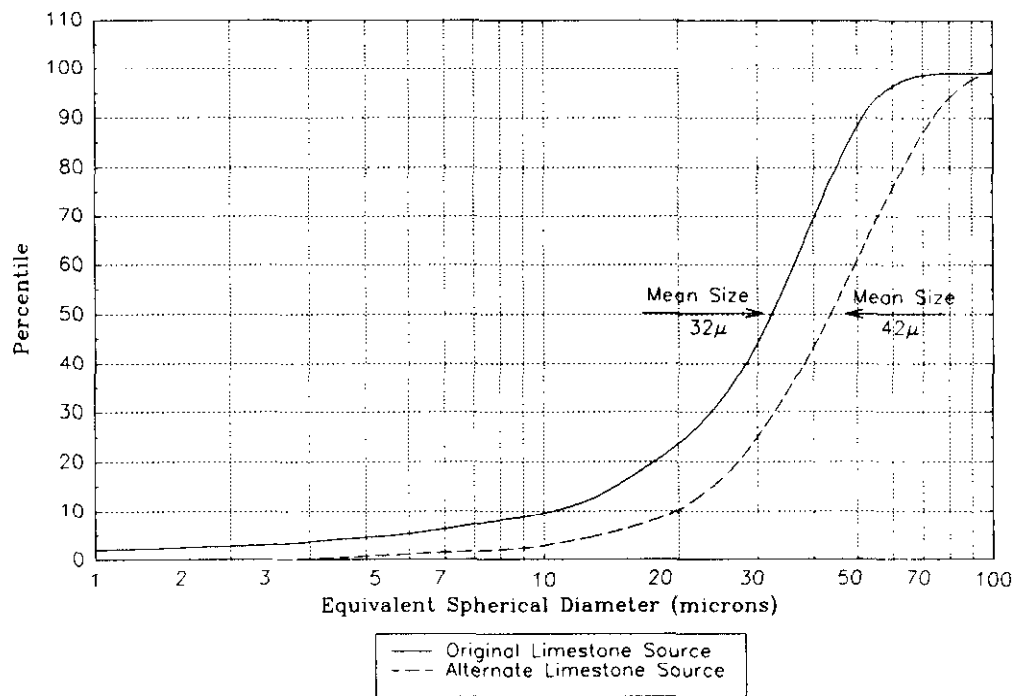


Figure 2. Effect of Limestone Reagent Source on Gypsum Particle Size

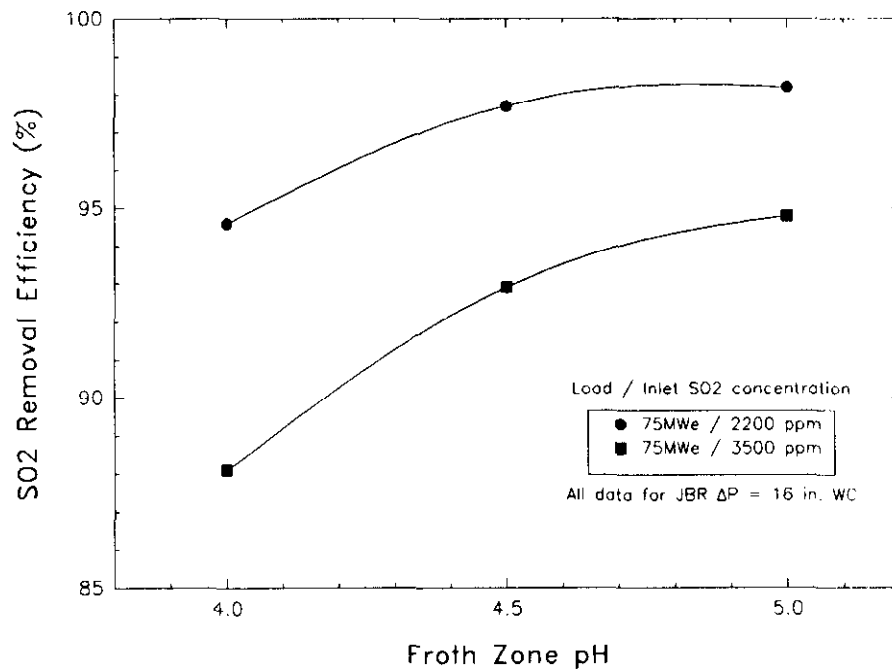


Figure 3. Effect of Coal Sulfur Content of SO_2 Removal Efficiency

TECHNICAL SESSION 10:

COMBINED NO_x/SO₂
CONTROL TECHNOLOGIES

Co-Chairs:

Gerard Elia

Pittsburgh Energy Technology Center
U.S. Department of Energy

William E. Fernald

Office of Clean Coal Technology
U.S. Department of Energy

Dennis N. Smith

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DEMONSTRATION OF GAS REBURNING-SORBENT INJECTION ON A CYCLONE-FIRED BOILER

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Chicago, Illinois

Abstract

Demonstration of Gas Reburning-Sorbent Injection on a 33 MW cyclone-fired boiler exceeded the program goals of 60 percent NO_x reduction and 50 percent SO₂ reduction. The results of the parametric, long-term, and extended operation testing at the Lakeside Unit 7 of City Water Light and Power are presented in this paper.

Gas Reburning-Sorbent Injection (GR-SI) is a combination of two technologies that have been extensively studied and well documented in recent years. Gas Reburning is a process where a part of the primary fuel is replaced by natural gas injected into the furnace above the primary fuel (coal, gas or oil) creating a fuel rich zone where NO_x reduction takes place due to reaction with the

hydrocarbon fragments generated from natural gas. In the Sorbent Injection process, SO₂ reduction is achieved when hydrated lime sorbent is injected into the upper furnace at a temperature favorable to calcination of the sorbent and reaction of calcium oxide and sulfur dioxide to form calcium sulfate.

Parametric testing was carried out for three months to optimize the process for the cyclone fired unit. Nine months of long term testing confirmed the operability of the unit and NO_x/SO₂ reduction goals throughout the unit's normal duty cycle. Extended testing followed to evaluate the combined processes during 104 hours of continuous operation.

Introduction

The Energy and Environmental Research Corporation (EER) has conducted a demonstration of Gas Reburning-Sorbent Injection (GR-SI) on a cyclone-fired boiler as part of the U. S. Department of Energy's Clean Coal Technology Program. GR-SI was retrofitted into two full scale utility boilers for simultaneous reduction of NO_x and SO₂ by 60 percent and 50 percent, respectively. The first demonstration was at the tangentially fired Illinois Power Hennepin Station Unit 1 (Ref. 1-5). This paper details the results of the GR-SI demonstration at the cyclone-fired Lakeside Unit 7 of City Water Light and Power located in Springfield, Illinois. The field evaluation centered on the following:

- Parametric Tests: optimization of Gas Reburning and Sorbent Injection parameters to comply with the specific operating characteristics of a cyclone unit.
- Long-Term Tests: operation of the GR-SI process throughout the unit's normal nine month duty cycle to determine process performance during normal dispatch operation.
- Extended Operation: continuous operation of GR-SI to determine the effects of continuous operation on process performance, GR-SI equipment performance, and the unit's thermal performance.

Lakeside Unit 7 is a 33 MW pressurized cyclone unit fired with an Illinois bituminous coal containing 3 percent sulfur. Two 7 (2.1m) ft cyclones are mounted side by side on the front wall. Combustion gases leave the cyclones and pass through a refractory-lined primary furnace and a water-wall radiant furnace before entering the convective pass. The gases exit the boiler through a Ljungstrom air heater before mixing with the flue gases from an identical unit. The combined gas streams then enter an electrostatic precipitator before exhausting to the atmosphere.

Steam temperature control is achieved by the use of a drum type steam attemperator. The boiler cleaning system comprises 15 steam sootblowers, seven of which are retractable IKs located in the convective pass.

Parametric tests were conducted in three series at the Lakeside boiler: Gas Reburning parametric tests, Sorbent Injection parametric tests, and GR-SI optimization tests. The goal of the parametric test series was to define the optimum GR-SI operating conditions with minimal degradation of the thermal performance of the boiler and to evaluate the GR-SI process over a wide range of representative operating conditions.

Process Description

Gas Reburning and Sorbent Injection can be applied together to achieve combined NO_x and SO_2 control in an easily retrofitted system. The two processes are complementary. Their application does not depend on the characteristics of the primary combustion system. They are applicable to any coal-fired boiler including stokers, cyclones and pulverized coal-fired equipment. Some recent references are given at the end of this paper.

Reburning is a NO_x reduction process which has been extensively studied over the last 20 years. It is a process which readily lends itself to cyclone fired units which can not be retrofitted with other in-furnace NO_x control techniques. Figure 1 shows a schematic of the Lakeside GR-SI system. The process is divided basically into three zones: a fuel lean primary combustion zone, a fuel rich reburn zone, and a burnout or overfire air zone.

- Primary Zone: The heat released in the primary combustion zone usually accounts for 75-85 percent of the total heat release. Suitable residence time and excess air (13 to 15%) are provided to minimize the number of unburned fuel fragments entering the reburning zone. In addition, in a slagging boiler like Lakeside Unit 7, it is important to maintain a sufficient heat release in order to maintain slag viscosity, which depends on ash characteristics, *temperatures and stoichiometry within the cyclone.*
- Reburning Zone: The remaining 15 to 25 percent of the heat is released by injection of natural gas transported by recirculated flue gas into the reburning zone under fuel rich conditions. In this environment, the NO_x from the primary combustion zone reacts with hydrocarbon fragments formed during the oxidation of the reburning fuel to form intermediate nitrogen species. A substantial portion of these intermediate nitrogen species

are converted to N_2 according to the process mechanism in Figure 2. This is a simplified view of a very complex series of reactions. The detailed chemistry is discussed in Reference 6.

- **Burnout Zone:** In the final zone, air is supplied to produce overall fuel lean conditions and to oxidize the remaining fuel fragments to complete the combustion process.

The direct injection of dry calcium based sorbent materials into the furnace space (Furnace Sorbent Injection or FSI) is a well known SO_2 control technique which has been frequently demonstrated in recent years. The sorbents that are most typically used are limestone ($CaCO_3$) or hydrated lime [$(Ca(OH)_2)$], injected at flue gas temperatures around 2,200°F (1200°C). Under these conditions, the injected sorbent is calcined *in situ* to form CaO which subsequently reacts with SO_2 to form a dry, solid $CaSO_4$. The dry product, which consists of $CaSO_4$, unreacted CaO, and fly ash, passes through the boiler to the downstream particulate collection equipment for removal. The process has been offered as a low capital cost alternative to scrubbers and is suitable for units where the capacity factor is low and only moderate levels of SO_2 removal are required.

The retrofit equipment must be designed within the specific constraints of the existing furnace and this requires a site-specific design. Flow modeling studies were undertaken to simulate aerodynamic mixing of the injected reburning streams and burnout air streams with the bulk flue gas. EER's numerical computer models were also used to predict NO_x and SO_2 reduction and thermal performance during GR-SI operation.

Gas Reburning Parametric Tests

A total of 100 Gas Reburning parametric tests were conducted at boilers loads of 33, 25, and 20 MW. Gas heat input varied from 5 percent to 26 percent, flue gas recirculation from 3 to 12 percent, primary zone stoichiometries (SR1) from 1.08 to 1.28 and burnout stoichiometries (SR3) up to 1.47 were tested. In addition, injection nozzle configuration and injection nozzle diameter were varied to enhance the mixing characteristics of the reburning fuel with the bulk flue gas entering from the primary zone.

In Figure 3, NO_x is plotted as a function of the gas heat input individually for each boiler load. Optimum NO_x reduction was achieved at about 22 to 23 percent gas heat input. CO emission of less than 100 ppm was recorded as shown in Figure 4. In terms of reburning zone stoichiometry

(SR2), optimal conditions are reached at ratios between 0.90 and 0.92 (Figure 5). The NO_x reductions at the optimum conditions were 60 percent at full load, 55 percent at mid-load, and 62 percent at low load.

Overfire air was optimized to achieve low CO emissions while maximizing NO_x reduction. Figures 6a, 6b and 6c show NO_x emissions as a function of burnout stoichiometry at each boiler load. For the most part, CO emissions of less than 200 ppm were achieved at burnout stoichiometries above 1.25 at full load, 1.28 at mid load, and 1.35 at low load. As the overall excess air was reduced there was a tendency for CO emissions to increase below SR3=1.25 to 1.30 under some conditions; therefore SR3=1.30 was established as the nominal lower boundary.

Flue gas recirculation (FGR) was used to enhance the penetration characteristics of the reburning fuel jets. Figures 7 and 8 show the impact of jet penetration on NO_x emissions. Figure 7 shows that increased FGR improved NO_x reduction at FGR rates up to approximately 11 percent. In terms of the ratio of the bulk flue gas momentum to the reburning jets momentum, it is evident that increased momentum flux ratio increased NO_x reduction performance (Figure 8).

The reburning parametric tests achieved NO_x reduction levels either at or just marginally above the 60% reduction goal. Additional flow modeling and computer modeling studies indicated that smaller reburning fuel jet nozzles could increase reburning fuel mixing and consequently improve the NO_x reduction performance. The results of this change are discussed later under GR-SI Optimization Tests.

Sorbent Injection Parametric Tests

The effects of boiler load, Ca/S ratio, and injection velocity were studied during the Sorbent Injection parametric tests. A total of 25 tests were completed. These were performed in order to isolate the effects of the sorbent on boiler performance and operability.

Figures 9a, 9b and 9c show that the SO₂ reduction level varied with load because of the effect of temperature on the sulfation reaction. Full load, corresponding to flue gas temperatures near the 2200°F (1200°C) optimum observed at pilot-scale and the full scale Hennepin GR-SI demonstration on a 71 MWe tangentially fired boiler, resulted in higher SO₂ reductions compared to the other two normal operating loads. At Ca/S ratio of 2.0, full load of 33 MW achieved 44

percent SO₂ reduction, mid-load (25 MW) achieved 38 percent SO₂ reduction, and low-load (20 MW) achieved 32 percent SO₂ reduction.

GR-SI Optimization Tests

Upon completion of the two separate parametric test series, the technologies were integrated as the last task prior to the long-term test program. Modifications were made to the reburning fuel injection nozzles based on the results of the initial Gas Reburning parametric tests and flow modeling studies. These studies indicated that an increase in the reburning jets momentum flux ratio could lead to an increase in NO_x reduction. The total cross sectional area of the reburning jets was decreased by 32 percent to increase the reburning jets penetration characteristics. The new nozzles were installed in October 1993. The decrease in nozzle diameter increased NO_x reduction by an additional 3-5 percent compared to the initial parametric tests as shown in Figure 10. The improvement was due to better mixing of the reburning fuel with the primary combustion products. The additional reduction would allow the project goals for NO_x control to be exceeded at the three normal operating loads.

With GR-SI, total SO₂ reduction results from the partial replacement of coal with natural gas and from Sorbent Injection. Additionally, the delay in heat release with Gas Reburning could have an impact on the reaction of SO₂ with CaO by raising the temperature of the sulfation window in the upper furnace. However, the data did not indicate any adverse effect of the change in the thermal profile. SO₂ reductions above 50 percent could be achieved with Ca/S greater than 1.5 along with gas heat inputs of 22-25 percent. The total SO₂ reduction, as shown in Figure 11, from the combined effect of fuel replacement and Sorbent Injection exceeded the project goal of 50 percent reduction. For comparison, the sorbent injection (no reburning) curve is also shown.

Long-Term Tests

The primary goal of the long term test program was to operate GR-SI during the normal operating cycle of the Lakeside unit. The reduction goals of the project were to be met while maintaining the unit's operability and availability during a nine month test period. NO_x and SO₂ reductions are shown in Figures 12 and 13, respectively. The average NO_x reduction through June 2, 1994, was 62 percent after a total of 249 hours of Gas Reburning operation. The total SO₂ reduction after 221 hours of GR-SI operation was 55 percent. It should be noted that the Lakeside Unit typically

operates in cycling service with a very low capacity factor. We tested whenever the unit was operating.

An important part of the test program was to identify the impact of GR-SI on the thermal performance of the Lakeside unit. The heat loss efficiency figures for Baseline, Gas Reburning, and GR-SI operation are shown in Figure 15. The 0.8% drop in thermal efficiency with GR-SI operation was due to the fuel switch (higher moisture from methane) and a small increase in the exit flue gas temperature due to sorbent deposition on back pass heat transfer surfaces. Figure 15 shows a 6 degree rise in the exit gas temperature with GR-SI operation compared to baseline operation. Carbon in ash data are still under evaluation.

Extended Operating Tests

During April and May of 1994, several extended tests were carried out to determine the effects of continuous operation on process performance as well as on boiler and ESP performance. These runs included a 38 hour GR-SI continuous run, a 115 hour GR-only continuous run, and a 66 hour continuous GR-SI run.

While data evaluation is still in progress, process operation with variable load was successful and met the project goals of 60% NO_x reduction and 50% SO₂ reduction. No significant boiler or ESP impacts were observed. Only minor mechanical problems were experienced with the ash handling and sorbent transport system during extended operations. Compliance test results for particulate emissions averaged 0.016 lb/MMBtu, well below the limit of 0.1 lb/MMBtu. The baseline dust loading was 0.0072 lb/MMBtu. With GR-SI, the flyash loading to the ESP increased by a factor of 6-7; therefore the very low outlet loading from the ESP attests to its design and performance.

Summary

The following results can be highlighted from the GR-SI demonstration project on the Lakeside Cyclone Fired Boiler:

- Exceeded project goal of 60% NO_x reduction at all boiler loads
- Exceeded project goal of 50% SO₂ reduction at all boiler loads (required Ca/S molar ratio decreases as load increases)
- Operated consistently and reliably
- Demonstrated no significant thermal impacts

- Controlled CO emissions by exit stoichiometry
- Provided satisfactory ESP performance during GR-SI operation. Compliance test particulate emissions averaged 0.016 lb/MMBtu compared to the allowable 0.1 lb/MMBtu. Baseline particulate emissions were 0.0072 lb/MMBtu.

Acknowledgments

The authors thank the US Department of Energy (DOE), the Gas Research Institute (GRI), and the State of Illinois Department of Energy and Natural Resources (IENR) for providing the funding under the Clean Coal Technology Program. The authors would also like to thank the operational and engineering staff at City Water Light and Power of Springfield, Illinois for their cooperation and assistance.

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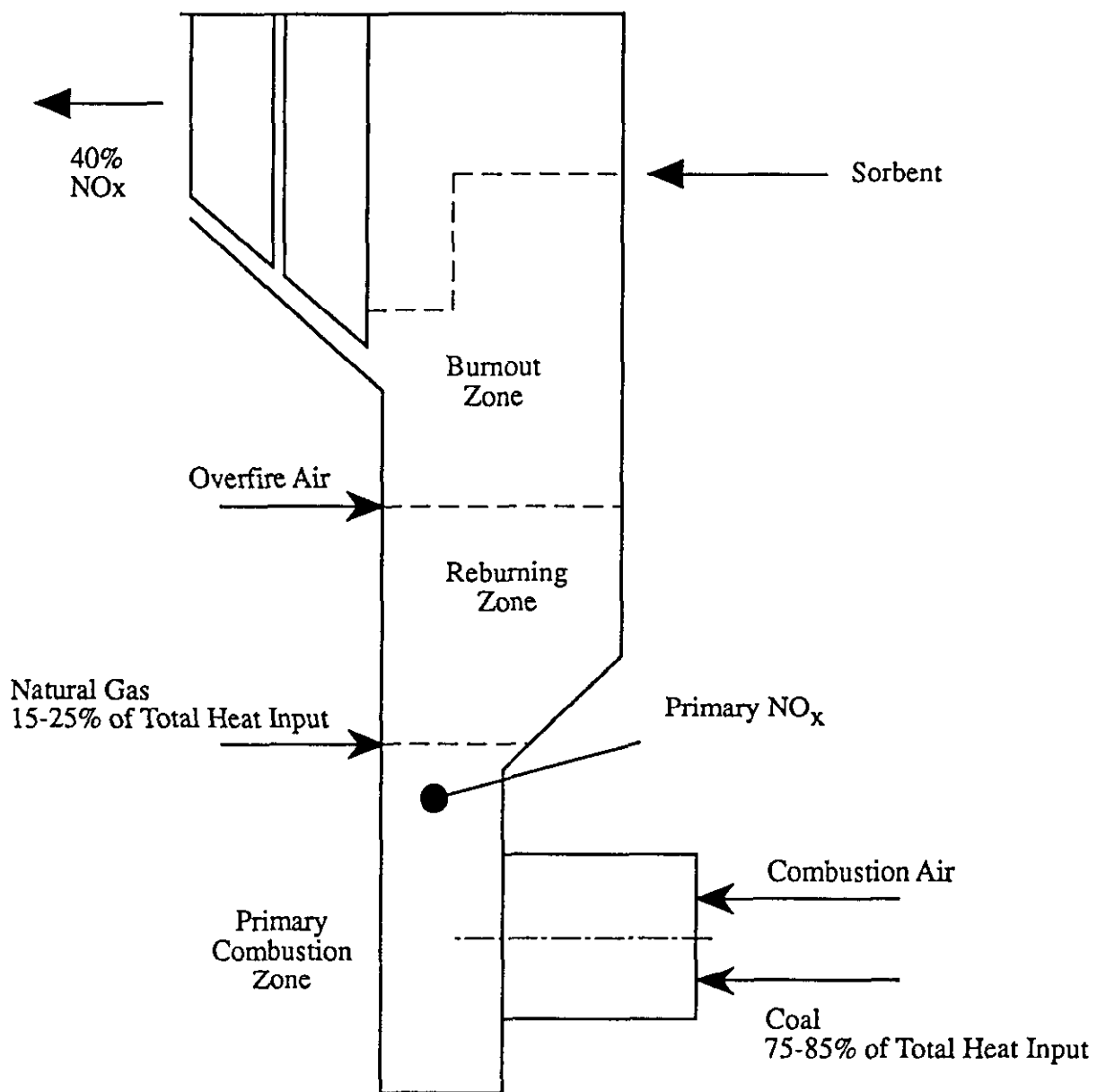


Figure 1. Schematic of the Lakeside GR-SI system.

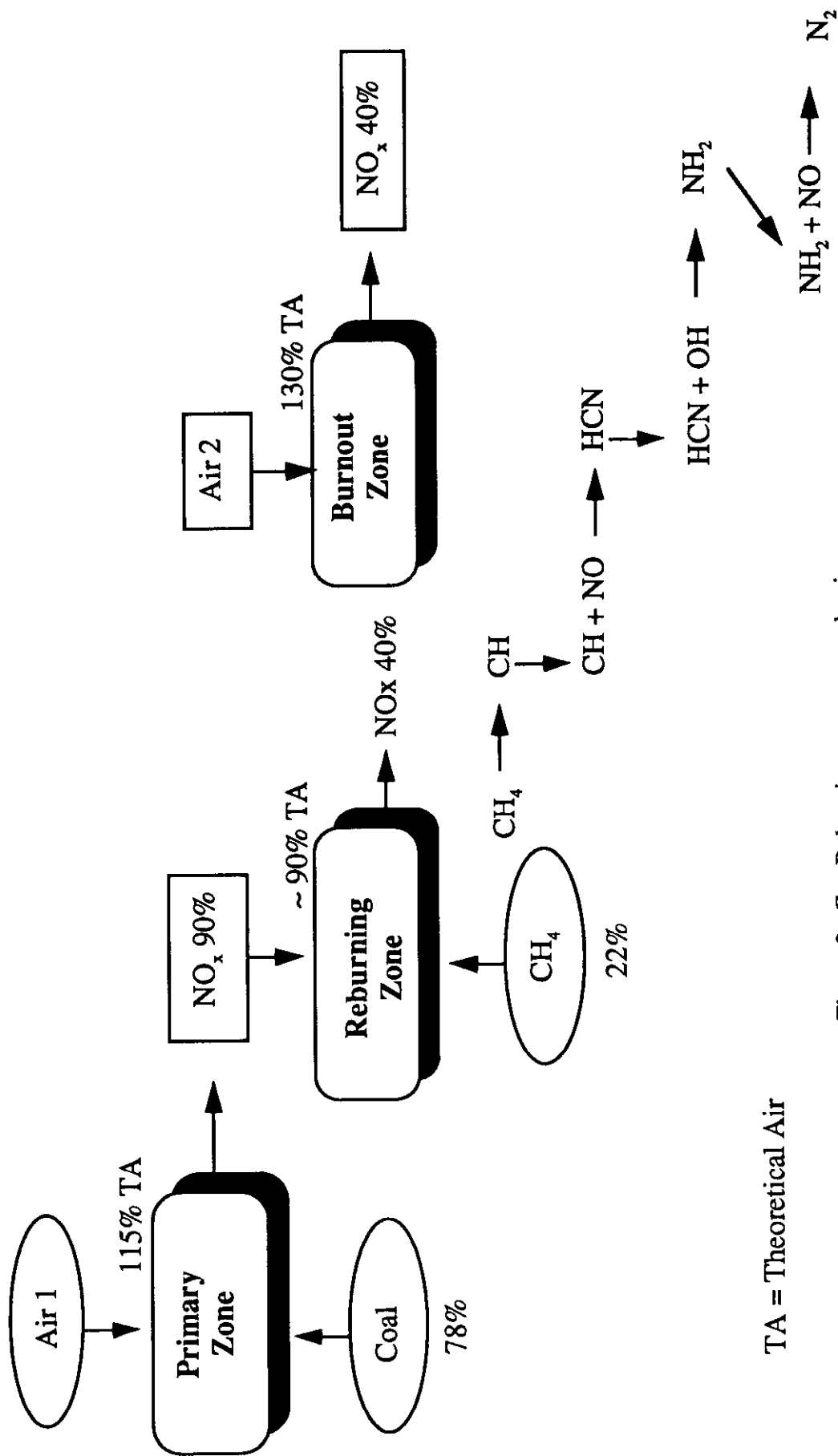


Figure 2. Gas Reburning process mechanism.

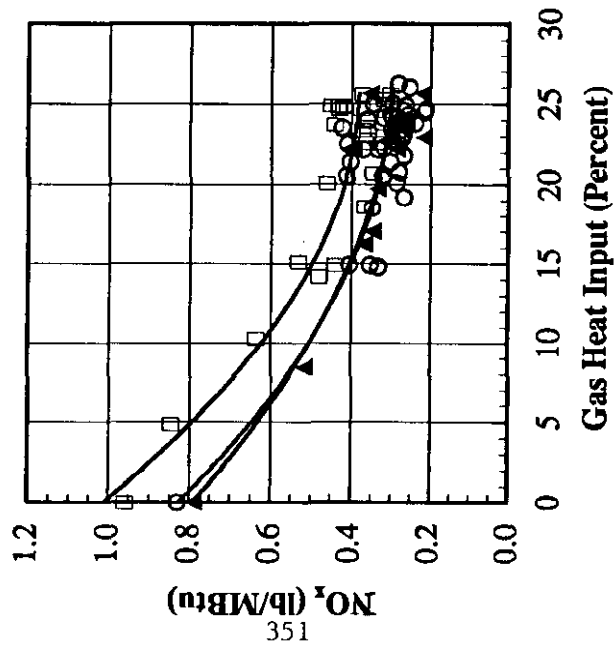
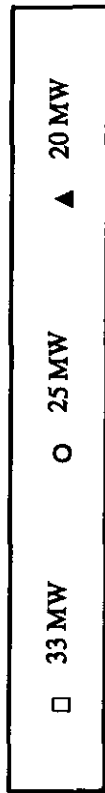


Figure 3. Effect of gas heat input on NO_x emissions.

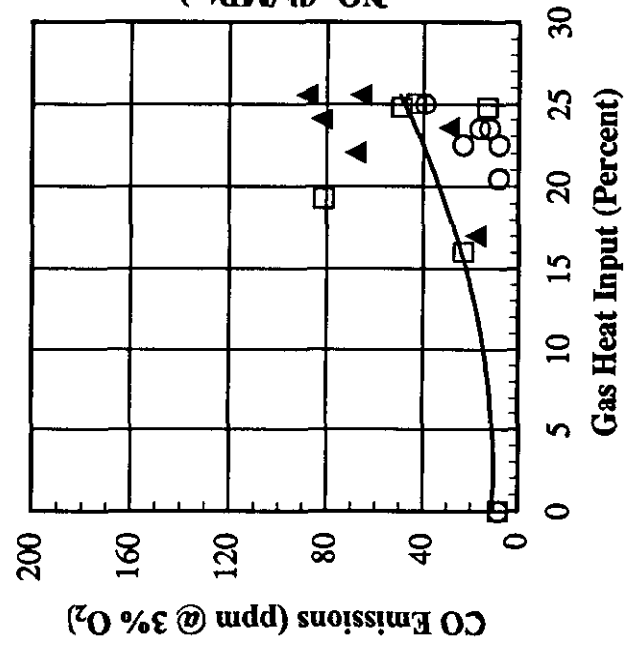


Figure 4. Effect of gas heat input on CO emissions.

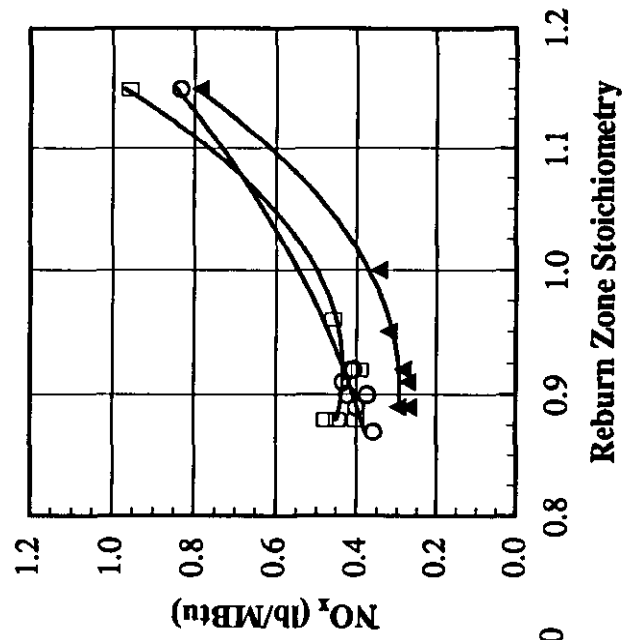


Figure 5. Effect of Reburn zone stoichiometry on NO_x emissions.

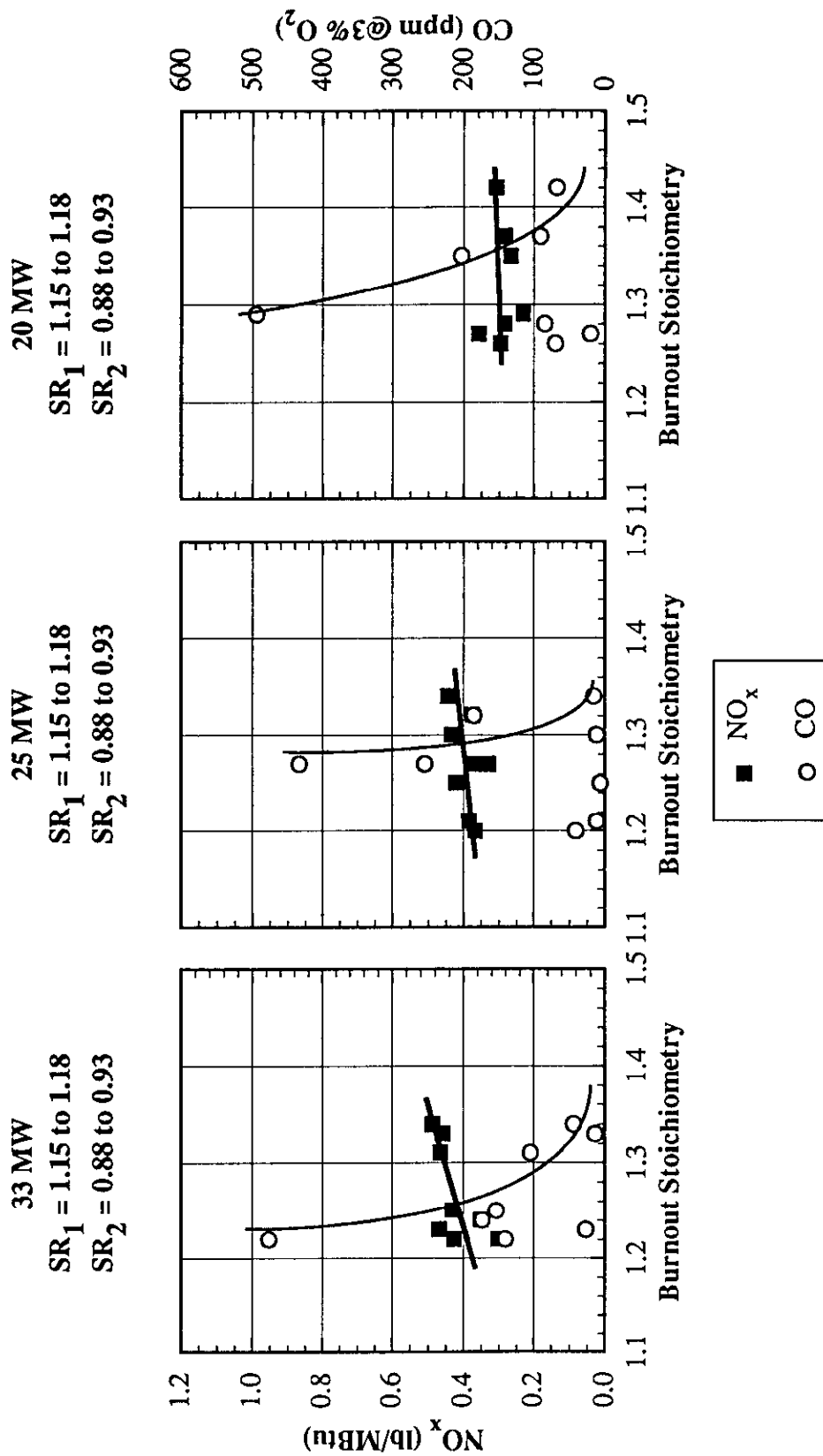


Figure 6a

Figure 6b

Figure 6c

Figure 6. Effect of burnout stoichiometry on NO_x and CO emissions at three different boiler loads.

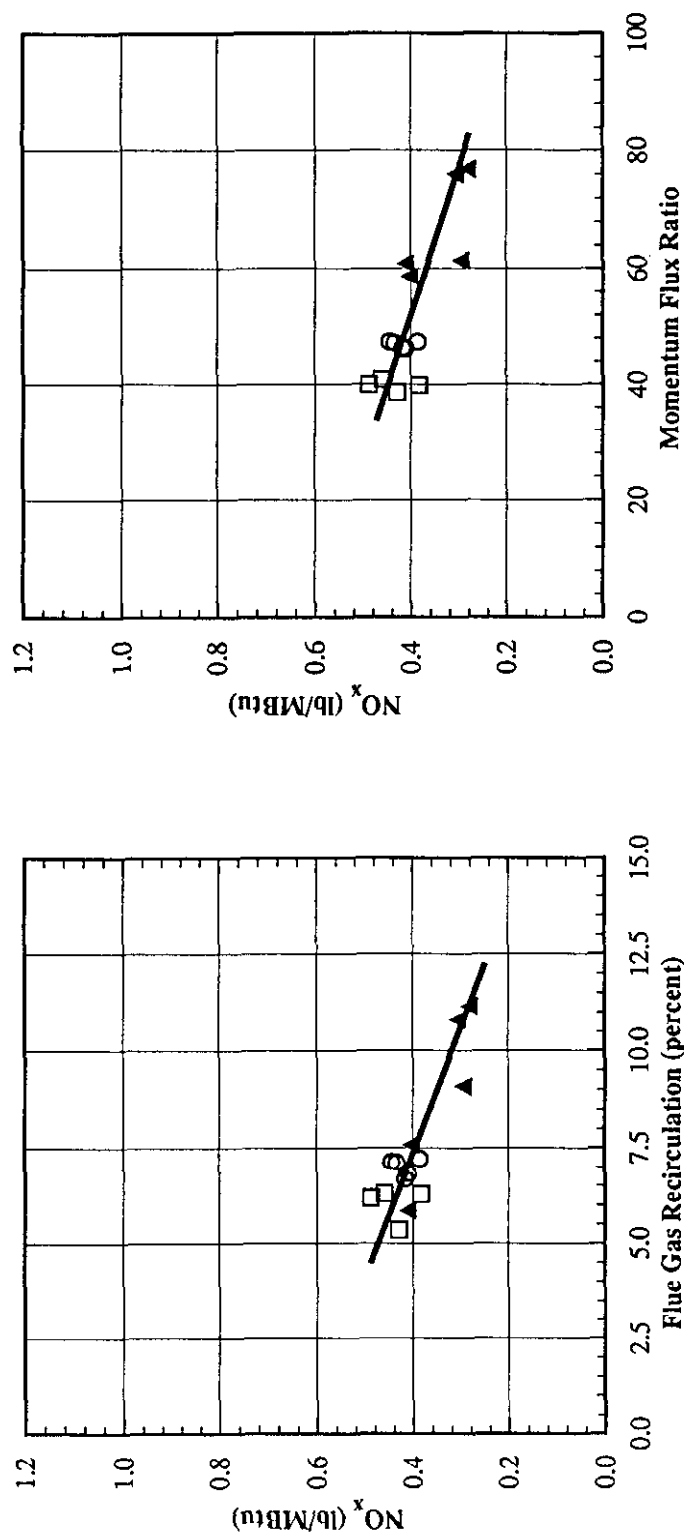
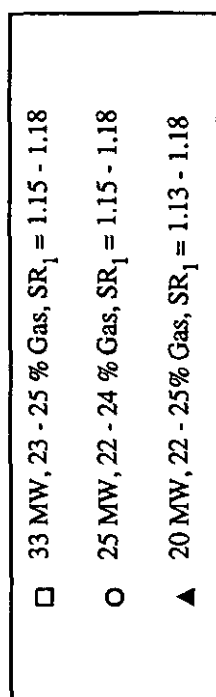


Figure 7. Effect of flue gas recirculation on NO_x emissions.

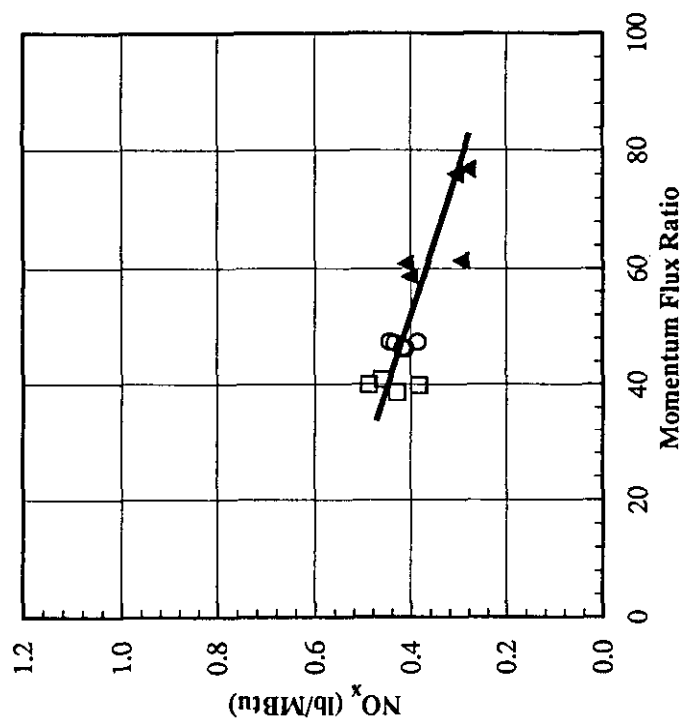


Figure 8. Effect of momentum flux ratio (bulk flue gas momentum/reburning jet momentum) on NO_x emissions.

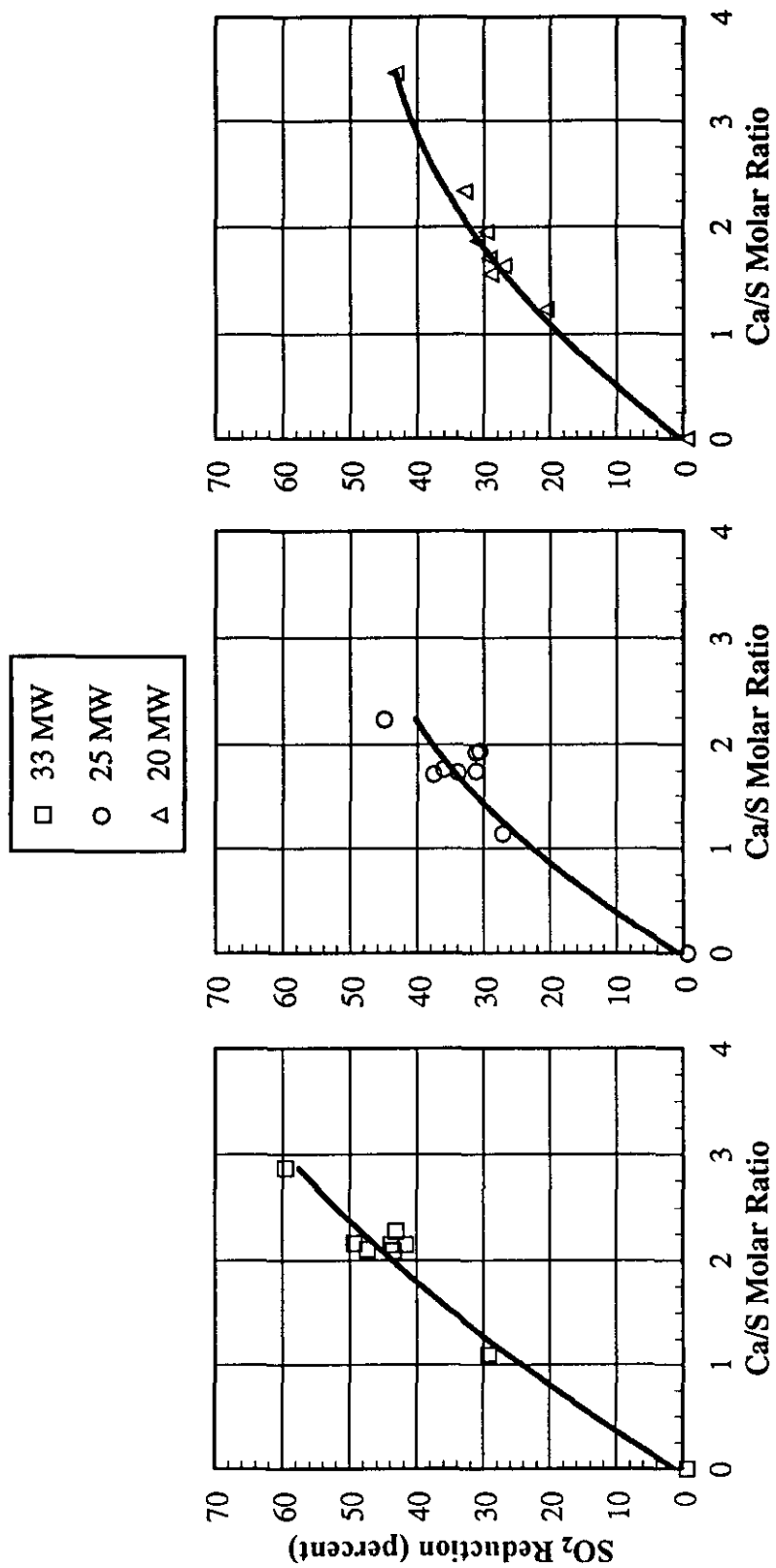


Figure 9a

Figure 9b

Figure 9c

Figure 9. Effect of Ca/S molar ratio on SO₂ reduction at three different boiler bads.

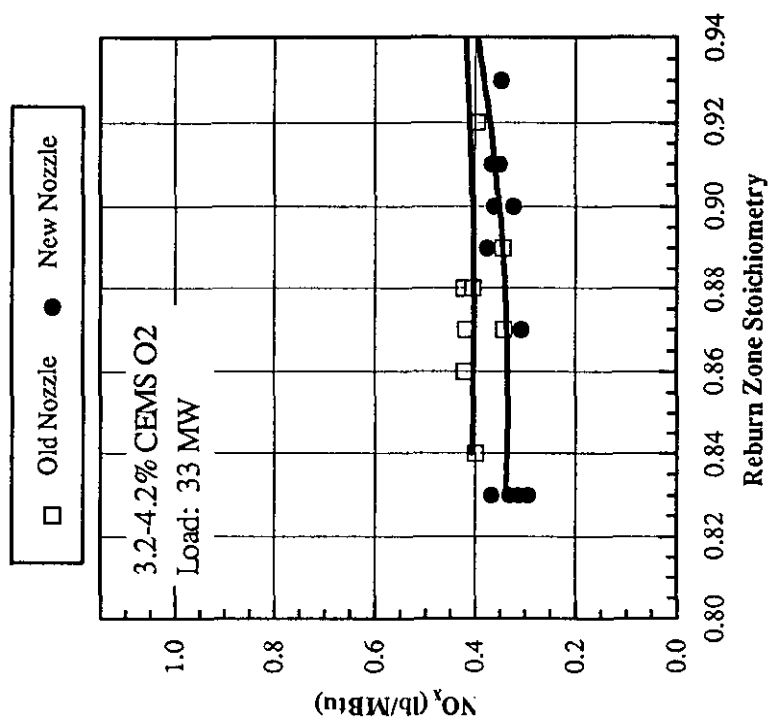


Figure 10. Effect of modified nozzle on NO_x emissions.

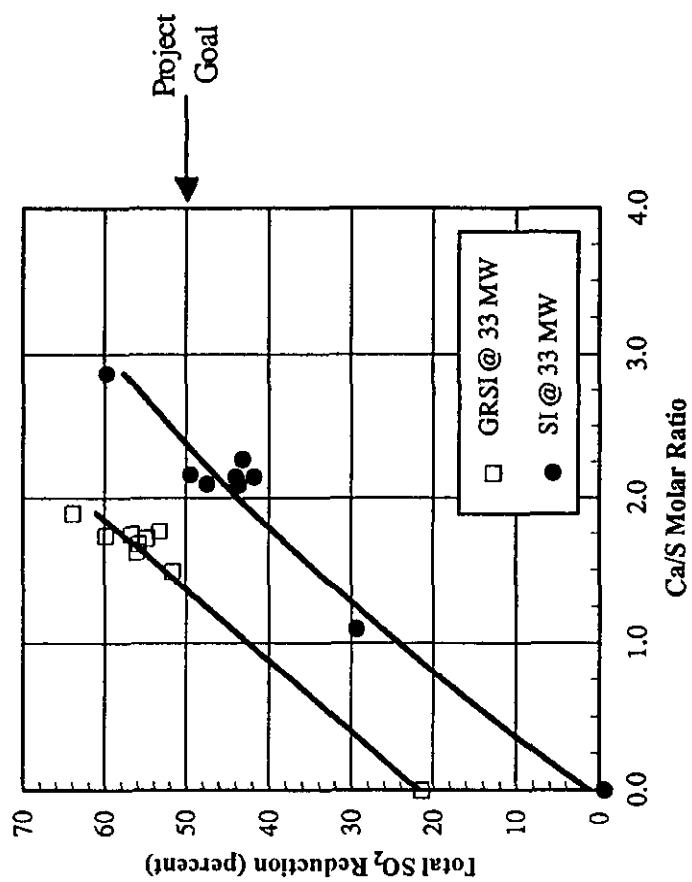


Figure 11. Effect of Ca/S molar ratio on SO_2 reduction.

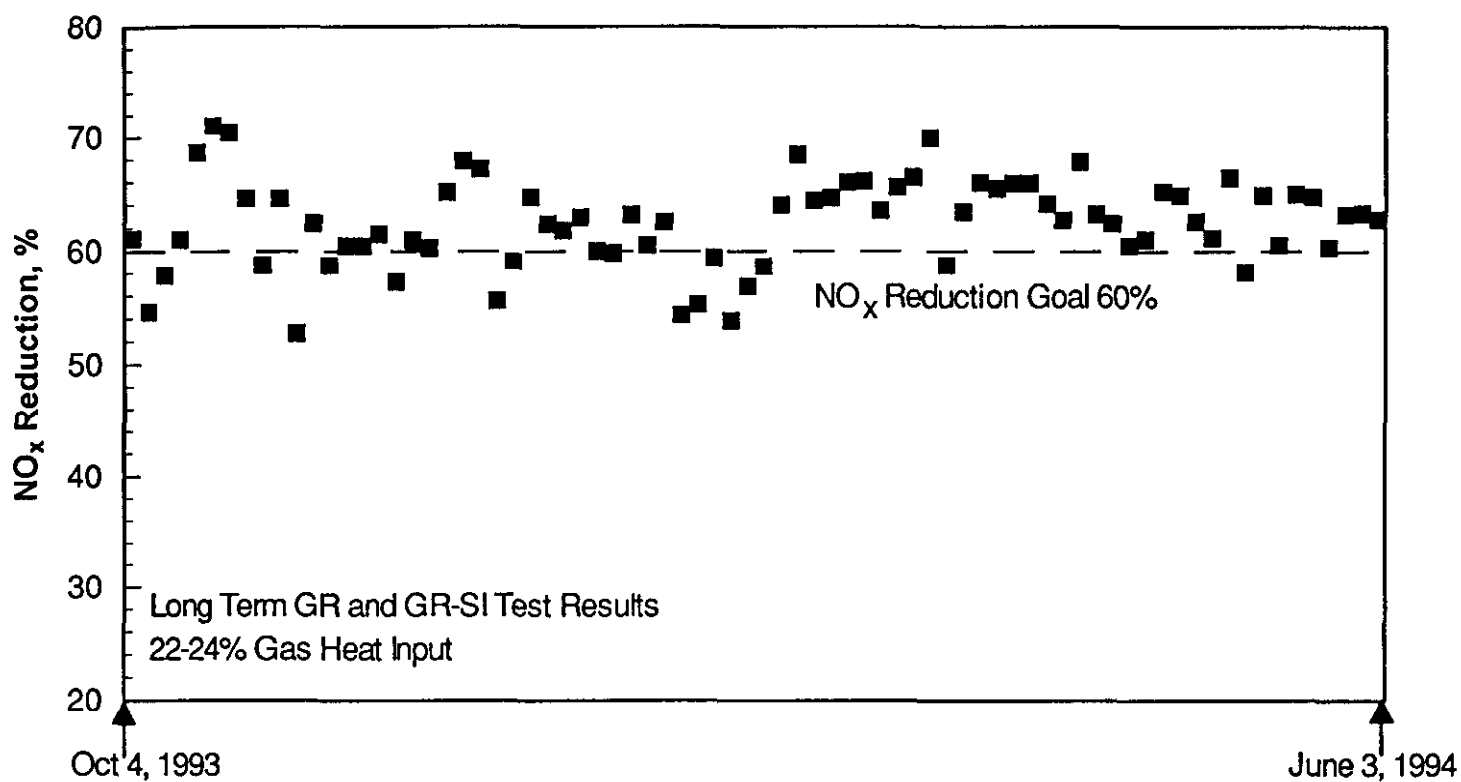


Figure 12. Long term operation results for NO_x reduction.

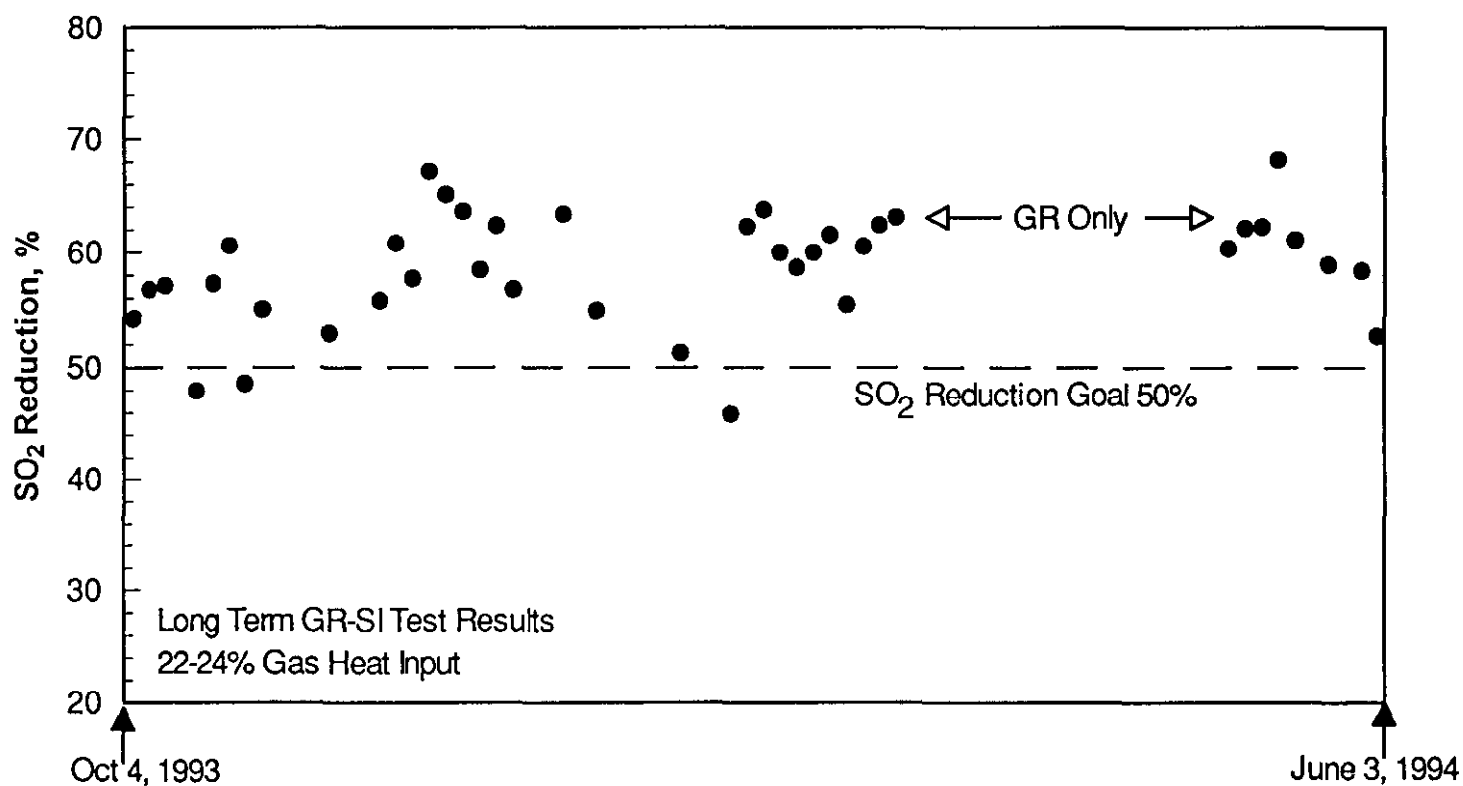


Figure 13. Long term operation results for SO₂ reduction.

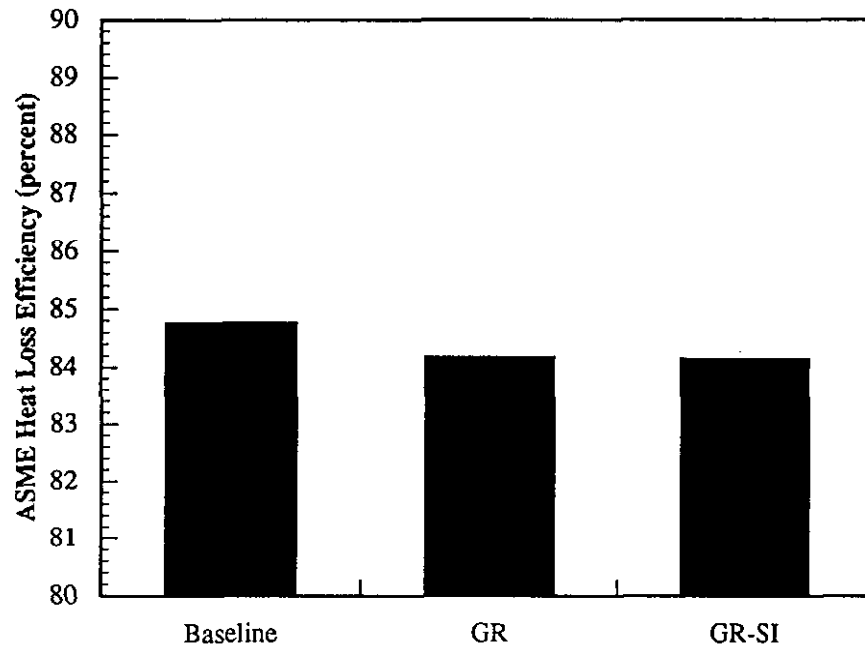


Figure 14. Comparison of ASME heat loss efficiency for Baseline, Gas Reburning, and Gas Reburning-Sorbent Injection operation.

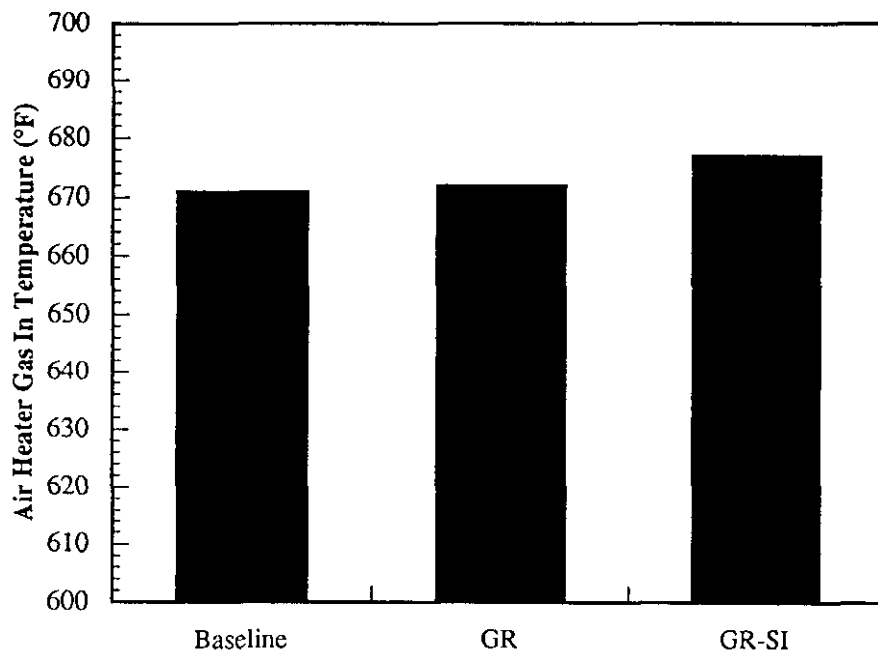


Figure 15. Comparison of air heater inlet temperatures for Baseline, Gas Reburning and Gas Reburning-Sorbent Injection.

COMMERCIALIZATION OF THE SNOX PROCESS THROUGH THE CLEAN COAL TECHNOLOGY PROGRAM

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ABSTRACT

The SNOX process, developed by Haldor Topsoe A/S and demonstrated and marketed in North America by ABB Environmental Systems (ABBES), is an innovative process which removes both sulfur dioxide and nitrogen oxides from power plant flue gases. Sulfur dioxide is recovered as sulfuric acid and nitrogen oxides are converted to nitrogen gas and water vapor; no additional waste streams are produced. As part of the Clean Coal Technology Program, this project is being demonstrated under joint sponsorship from the U.S. Department of Energy, Ohio Coal Development Office, ABBES, Snamprogetti, and Ohio Edison.

The project objective is to demonstrate the SO₂/NO_x reduction efficiencies of the SNOX process on

an electric power plant firing high-sulfur Ohio Coal. A 35-MWe demonstration is being conducted on a 108-MWe unit, Ohio Edison's Niles Plant Unit 2, in Trumbull County, Ohio. The \$31 million project began site preparation in November 1990 and commenced treating flue gas in March of 1992. A thirty three month test program is currently in progress and is scheduled for completion in December of 1994. Ohio Edison will continue operation of the plant at the conclusion of the test program.

Performance results indicate efficiencies in excess of the design goals of 90% NO_x removal and 95% SO₂ removal. Sulfuric acid concentration has also met the design goal of >93 wt. %, and the color and clarity of the acid continue to meet expectations.

INTRODUCTION

The SNOX process is a totally catalytic process for the reduction of sulfur oxides and nitrogen oxides in gaseous streams. The process was developed in Europe by Haldor Topsoe A/S and is offered under license throughout most of the world by ABB Environmental Systems for utility and large industrial boilers. The U.S. Department of Energy (DOE), through its Clean Coal Technology Program, is participating with the Ohio Coal Development Office (OCDO), Ohio Edison, Snamprogetti USA, and ABBES in a demonstration of this advanced new technology. The SNOX Demonstration Project is located at the Niles Power Plant of Ohio Edison near Niles, Ohio in Trumbull County.

Nitrogen oxides are decomposed to elemental nitrogen and water vapor, and sulfur oxides are converted to commercial grade sulfuric acid - both at very high efficiency. The production of sulfuric acid rather than sludge eliminates the waste disposal problem associated with conventional lime/limestone WFGD systems and also contributes to the low operating cost of the process. Other features of the process which reduce operating costs are the recovery of thermal energy from the flue gas stream and the lack of a reagent requirement for SO₂ removal. Further, the process does not generate secondary sources of pollution such as waste water, slurries or solids. The process operates over a wide range of unit loads and inlet SO₂ and NO_x concentrations with very little effect on

removal efficiencies and only minor adjustments to the process controls.

In addition to the U.S. Demonstration Plant, commercial plants have recently been started up in Denmark and Sicily. In Denmark, a 305 MW plant has been designed, constructed, and in operation since August of 1991. The boilers at this plant burn coals from various suppliers around the world, including the U.S., with sulfur contents varying from 0.5 to 3.0 percent. The plant in Sicily, operating since March 1991, is approximately 30 MW in capacity and is on a unit firing petroleum coke.

At the present time, the Demonstration Program in Niles, Ohio is in Phase III - Operation and Testing - and the formal test program will conclude in December of 1994. Following conclusion of the test program, Ohio Edison will assume ownership of the plant and continue operating the process. Also during Phase III some modifications to plant equipment are being incorporated to accommodate long term operation.

This paper presents an overview of the SNOX Demonstration Project and provides information on the system design, equipment and materials performance, test plan and test results. Commercialization status of the process at the present time is also discussed.

PROJECT DESCRIPTION

One of the sixteen projects selected for funding under Round II of the Clean Coal Technology Program was the SNOX process demonstration proposed by ABBES. The total project cost was projected to be \$31.4 million with the co-funders being: DOE (\$15.7 million); OCDO (\$7.8 million); ABBES and Snamprogetti (\$6.7 million); and Ohio Edison (\$1.2 million). The project was selected on September 28, 1988 and the Cooperative Agreement was signed on December 20, 1989.

The execution of the SNOX Demonstration Project is divided into three phases which span approximately sixty months. These phases are identified as follows (shown in Figure 1):

- Phase I Design and Permitting
- Phase IIA: Long Lead Procurement

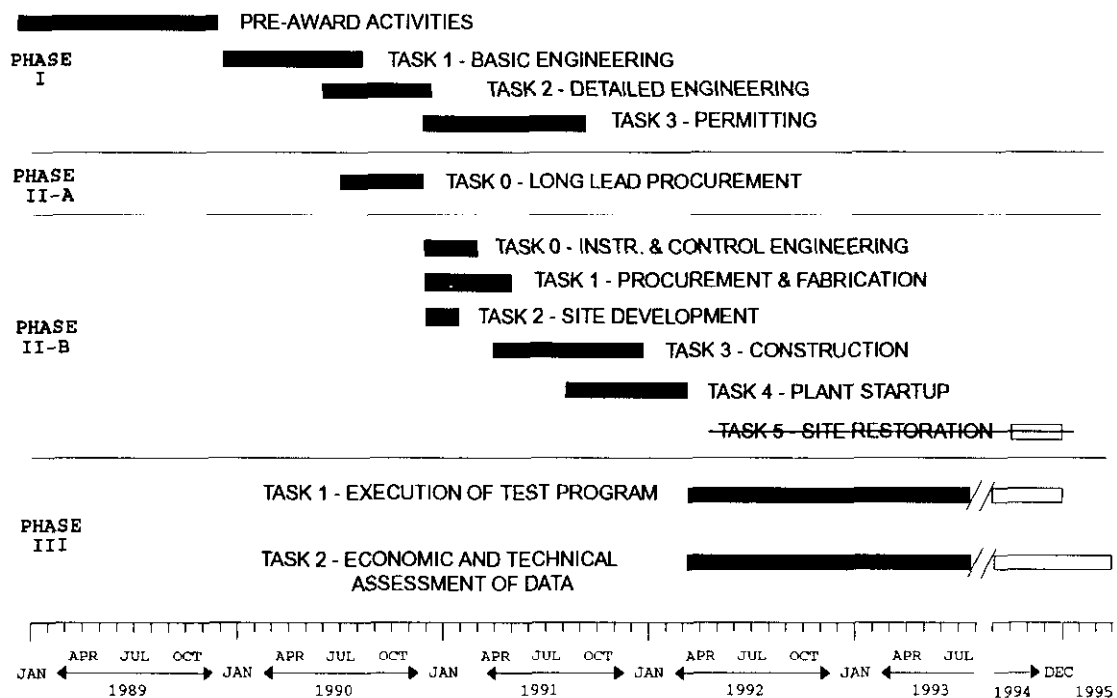


Figure 1
SNOX Project Schedule

- Phase IIB: Construction and Start-Up
- Phase III: Operation, Data Collection, and Reporting

Phase I of this project, Design and Permitting, was further broken down into Basic Engineering, Detailed Engineering and Permitting. Basic Engineering was completed in July of 1990, followed by the completion of the Detailed Engineering toward the end of that year.

Phase IIA was comprised of the procurement of long lead time items such as the baghouse, high temperature steel, control system, gas/gas heat exchanger, and the sulfuric acid (WSA) condenser. These items were purchased at the beginning of Detailed Engineering and arrived at the Niles Plant for installation between February and May of 1991. Site preparation and installation of foundations began in November 1990 and construction was completed in November of 1991. Equipment commissioning was conducted following completion of construction and the system was first operated on flue gas in March of 1992. The project is currently in Phase III of the program, and testing will continue until December of 1994.

Originally the overall program was 48 months in length and was scheduled to end in December of 1993. A task for Site Restoration was included in Phase II-B funding in the event that Ohio Edison did not opt to retain the plant. During the second half of 1993, Ohio Edison announced that it would retain the plant and funds that were designated for dismantling were reapportioned into the operating phase of the program for testing and system modifications. Part of Ohio Edison's decision to retain the plant hinged upon assurances by ABBES and DOE that existing auxiliary equipment and materials problems would be resolved. The test program was lengthened by twelve months to generate additional performance data and perform the system modifications.

As was stated, the project is currently in Phase III, Testing and Data Collection/Assessment. Although the formal test program is scheduled to end in December of 1994, the overall project will continue until March of 1995 to allow for completion of data assessment and reporting.

PROCESS DESCRIPTION

The SNOX technology consists of five (5) key process areas: particulate collection, nitrogen oxides (NO_x) reduction, sulfur dioxide (SO_2) oxidation, sulfuric acid (H_2SO_4) condensation and sulfuric acid management. Heat transfer and recovery also represent a significant part of the SNOX system. The integration of these individual steps is shown in Figure 1, which is the process flow diagram for the system installed on the Niles Unit 2 boiler.

Referring to Figure 1, a slip stream from the Unit 2 boiler is taken upstream of the existing electrostatic precipitator and heated to approximately 400° F by an in-line natural gas fired burner before entering a fabric filter for particulate collection. The flue gas is heated to simulate the inlet temperature to a SNOX system for a full size installation, wherein preheated combustion air produced by the SNOX process and supplied to the boiler air heater would result in higher outlet flue gas temperatures. After passing through a booster fan, the flue gas is heated to above 700° F through the primary side of a gas/gas heat exchanger (GGH).

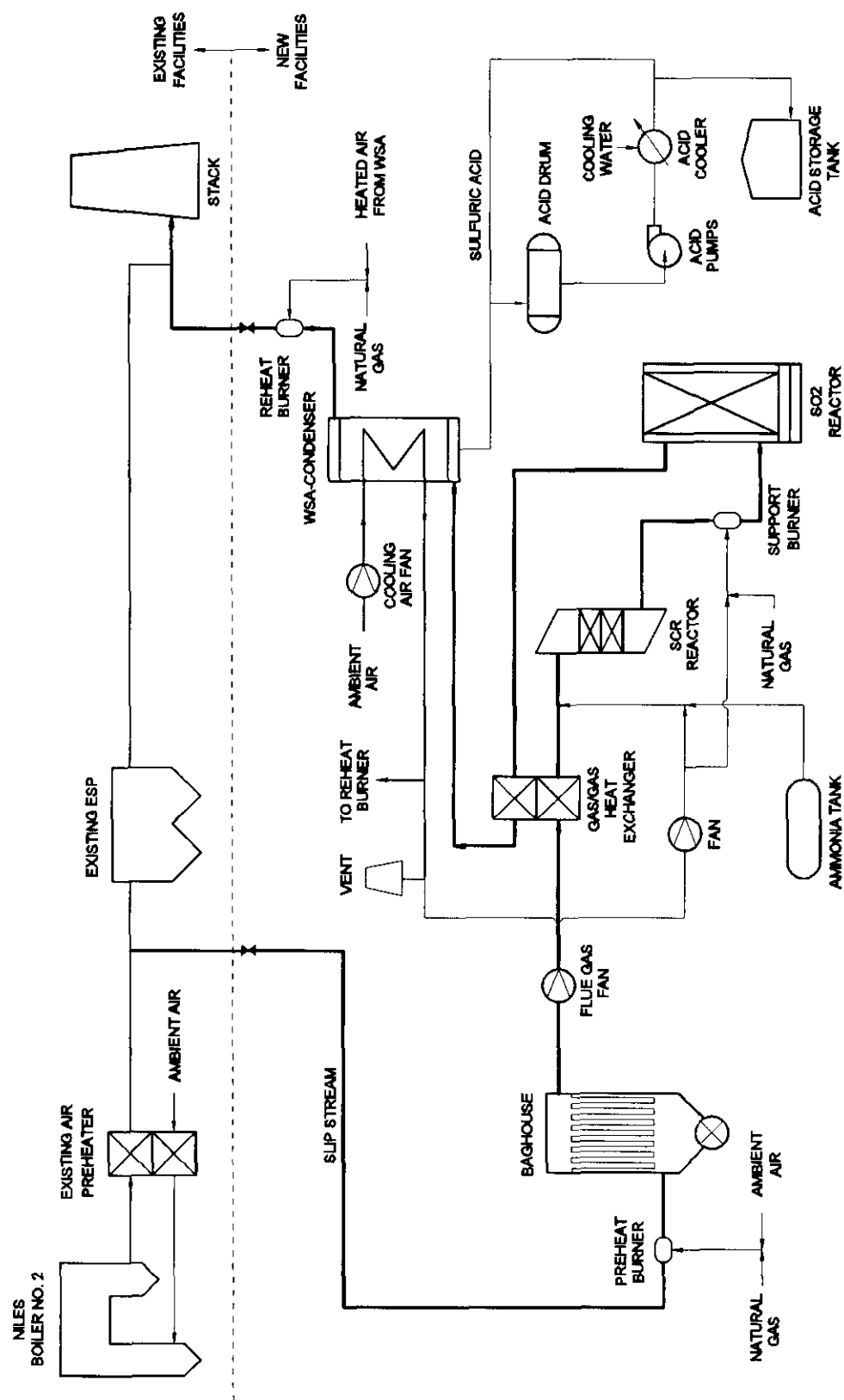


Figure 2
Niles SNOX Plant Process Flow Diagram

An ammonia and air mixture is then added to the gas prior to the selective catalytic reactor (SCR) where nitrogen oxides are reduced to free nitrogen and water. The flue gas leaves the SCR, its temperature is raised slightly by an in-line burner, and enters the SO₂ Converter which oxidizes SO₂ to sulfur trioxide (SO₃). The SO₃ laden gas is passed through the secondary side of the GGH where it is cooled as the incoming flue gas is heated.

The processed flue gas is then passed through a falling film condenser (the WSA Condenser) where it is further cooled with ambient air to below the sulfuric acid dewpoint. Acid condenses out of the gas phase on the interior of borosilicate glass tubes and is subsequently collected, cooled and stored. The flue gas is discharged from the process at about 210°F and cooling air leaves the WSA Condenser at approximately 400°F. In a full size, integrated SNOX system the hot air is used for process support and as boiler combustion air after collecting more heat through the air preheater.

For the SNOX demonstration at the Niles facility, the WSA Condenser cooling air is vented and not returned to the boiler air preheater because the entire boiler flue gas output is not being treated. Later in the program, the possibility of introducing the 400°F cooling air into the flue gas duct after the WSA condenser to eliminate the third burner was investigated but the gas duct was too small and budget constraints did not allow major design changes.

The hot, concentrated sulfuric acid product at about 400°F is collected and circulated through a thermoplastic lined system consisting of a holding tank, circulation pumps, and a water-cooled shell and tube heat exchanger. The purpose of this loop is to cool the acid to more conveniently manageable temperatures (70-100°F). Acid from the recirculation loop is then pumped to the main acid storage tank. During start-ups acid is temporarily routed to a second tank for a brief period until acid color and clarity meet requirements. Concentration is normally not a problem and is at commercial grade (93-94%) immediately after start-up.

The SNOX process has several advantages in comparison with other combined de-NO_x/de-SO_x methods and conventional technologies. These advantages are:

- No alkali reagent required for SO₂ removal
- No generation of secondary pollution streams such as solids, slurries, or liquids
- Production of a salable by-product - sulfuric acid
- Very low particulate emissions
- Minimal or no increase in CO₂ emissions
- Reduction of any CO and hydrocarbons in the flue gas
- Synergistic coupling of NO_x and SO₂ catalysts
- Furnace integration of recovered heat

Because the SNOX process utilizes an oxidation catalyst to convert SO₂ to SO₃ and ultimately to sulfuric acid, no reagent is required for the SO₂ removal step. As a result, no other waste streams are produced by the process. Particulate emissions from the process are very low (<1 mg/Nm³) due to the characteristics of the SO₂ catalyst and the sulfuric acid condenser (WSA Condenser). Although the Niles SNOX plant is fitted with a baghouse (rather than an ESP) on its inlet, this is not necessary for low particulate emissions but impacts the cleaning frequency of the SO₂ catalyst. At operating temperature, the SO₂ catalyst has a sticky surface and retains about 90% of the dust which enters the catalyst vessel. Any dust which passes through is subsequently removed in the WSA Condenser which acts as a condensing particulate removal device (utilizing the dust particles as nuclei).

Minimal or no increase in CO₂ emissions by the process is tied to two features - the lack of a carbonate-based alkali reagent which releases CO₂, and the fact that the process recovers additional heat from the flue gas to offset its parasitic energy requirements. This heat recovery, under most design conditions, results in the net heat rate of the boiler being the same or better after addition of the SNOX process, resulting in no increase in CO₂ generation per unit of power.

With respect to CO and hydrocarbons, the SO₂ catalyst acts to virtually eliminate these compounds as well. This aspect also positively affects the interaction of the NO_x and SO₂ catalysts. Because the SO₂ catalyst follows the NO_x catalyst, any unreacted ammonia (slip) is oxidized in the SO₂ catalyst to nitrogen, water vapor, and a small amount of NO_x. As a result, downstream fouling by ammonia compounds is eliminated and the SCR can be operated at slightly higher than typical ammonia stoichiometries. These higher stoichiometries allow smaller SCR catalyst volumes and permit the attainment of very high reduction efficiencies (>95%).

As mentioned previously, heat recovery is accomplished by the SNOX process and is utilized in the thermal cycle of the boiler. The process generates recoverable heat in several ways. All of the reactions which take place with respect to NO_x and SO_2 removal are exothermic and increase the temperature of the flue gas. This heat plus fuel-fired support heat added in the high temperature SCR/ SO_2 catalyst loop is recovered in the WSA Condenser cooling air discharge for use in the furnace as combustion air. Because the WSA Condenser lowers the temperature of the flue gas to about 210° F compared to the 300° F range of a typical power plant, additional thermal energy is recovered along with that from the heats of reaction.

TECHNOLOGY DEMONSTRATION

The SNOX process combines two Haldor Topsoe technologies, i.e. the innovative WSA process for the removal and recovery of sulfur dioxide as concentrated sulfuric acid and the Selective Catalytic Reduction (SCR) of nitrogen oxides. The first plant using the principles of the WSA, or Wet-gas Sulfuric Acid, process without selective catalytic reduction was commissioned in 1963 in Lacq, France. This plant, which used a conventional acid absorption tower with circulating sulfuric acid (WSA-1 process), treated a dust-free off-gas containing 1% SO_2 . In 1980, two additional WSA-1 plants, treating off-gas with 10-15% hydrogen sulfide (H_2S), were commissioned in Sweden.

Limitations of the conventional acid tower led to the design of the WSA Condenser and the development of the WSA-2 process which has replaced the WSA-1 process. The first industrial WSA-2 plant, cleaning 7,800 scfm (12,000 Nm^3/h) of off-gas from a molybdenum roaster in Sweden, has been in operation since May of 1986. The plant treats off-gas with 0.5-1.5% SO_2 at a removal efficiency of >95% and is recovering 95-96% sulfuric acid. Another WSA-2 plant designed to treat 78,000 scfm (125,000 Nm^3/h) of off-gas from a pulp mill in Taiwan was started up in 1990. Two additional contracts have recently been awarded for WSA-2 plants in Europe which will treat off-gases containing H_2S .

Between 1983 and 1985, Haldor Topsoe developed a catalyst for the denitrification of flue and exhaust gases. The first pilot testing of this catalyst was performed on diesel exhaust from a

stationary engine on the Faroe Islands. The WSA-2 process was then combined with this de-NO_x technology to form the SNOX process for simultaneous removal of NO_x and SO_x. The SNOX process was first tested in December of 1985 at the Amagerværket Power Station, Copenhagen, Denmark, with a 62 scfm (100 Nm³/h) bench-scale plant.

In November, 1987, a 3 MW (6,200 scfm, 10,000 Nm³/h) demonstration SNOX plant was started up at Skaerbaekværket, Skaerbaek, Denmark. Intended to provide process data for the engineering of full-scale coal-fired utility power boilers, this pilot plant was designed so that all critical equipment, such as the bag filter, catalytic reactors, and WSA Condenser, had the same modular sizes as in a full-scale plant. The WSA Condenser, for instance, used the same glass tubes, tube pitch, construction materials, and details of construction as would a larger unit. In 1991, having fulfilled its purpose, this facility was decommissioned.

In 1989 a contract for the retrofitting of an existing power plant (305 MW) with the SNOX process was signed with a Danish power producer, ELSAM. This plant was officially commissioned in November of 1991 and has been operating at design capacity (620,000 scfm, 1,000,000 Nm³/h) routinely. All guarantees have been satisfied with 95% removals of SO₂ and NO_x achieved. This station received the 1992 International Powerplant Award from Electric Power International Magazine for its balance of both energy and environmental needs.

Also in 1991, a demonstration scale SNOX plant was commissioned by Snamprogetti S.p.A which treats 62,000 scfm (100,000 Nm³/h) of flue gas from a petroleum coke (6% sulfur) fired power plant owned by Enichem S.p.A. in Italy. This plant has met or exceeded all process design objectives and is supplying sulfuric acid to an adjacent petrochemical complex for fertilizer production. Removals of SO₂ and NO_x are greater than 96% at this facility.

In late 1989, a contract with the U.S. Department of Energy was signed as part of the U.S. Clean Coal Technology Program, Round II, to demonstrate the SNOX process at a U.S. utility power station. This project, which is the subject of this paper, would serve to demonstrate the high performance of the SNOX technology in the North American power generation industry, i.e. with

U.S. fuels and operating staff. The project was also needed to prove the commercial quality of the sulfuric acid produced by the SNOX process in the U.S. marketplace.

Even though the technology had been fully characterized process-wise prior to the contracting of the DOE project, the final scale-up to utility size required additional experience. For instance, since all major components in earlier plants had been designed in a modular fashion utilizing full-scale components, scale-up would not result in any new process problems. However, achieving the correct distribution of flue gas or air through the various module groups that existed in the WSA Condenser, SO₂ Converter, and SCR remained to be demonstrated at full scale. This final scale-up experience could be obtained through the DOE project.

The design of the DOE project was specifically aimed at demonstrating all SNOX subsystems and integrations that would be needed with a full scale installation. For example, all flue gas conditions such as temperatures, pressures, and compositions were exactly replicated and all support systems, such as the control system, ammonia supply, and product acid storage and distribution were designed and operated as with a full scale system. The only concept that could not be accommodated by the design was the integration of the WSA Condenser discharge air as preheated combustion air for the boiler. This was not possible since the project would only treat one third of the flue gas from the host boiler and would not result in a large enough quantity of combustion air. The principles involved with this integration, i.e. gas/gas heat exchanger design and preheated air for combustion, were believed to be fully understood and not crucial to the demonstration.

Both the DOE project and the 305 MW ELSAM SNOX plant were designed, constructed, and commissioned on virtually parallel timetables and to date both SNOX facilities have been proven to perform and operate as designed. The final step to full scale experience that these two plants represent was not without obstacles. As expected, obtaining correct gas distribution presented problems with the SCR (at Niles) and the WSA Condenser (at ELSAM). These cases of maldistribution were correctable with conventional methods. One area of complication that was not expected, however, involved corrosion and materials of construction at the SO₂ Converter outlet expansion joints and the WSA Condenser outlet duct lining.

The WSA Condenser outlet duct was coated initially with an epoxy based coating. Over the two year demonstration the coating deteriorated exposing the A36 carbon steel ductwork. Since the outlet of the WSA Condenser is at the sulfuric acid dewpoint, even the low mist concentration from the condenser (<5 ppm normally) results in the walls of the duct being wetted. In consulting the ELSAM SNOX plant in Denmark it was confirmed that they had similar problems but were experiencing good success with a vinyl ester coating. Although the Niles SNOX plant ductwork had little metal loss (measured after the duct was partially cleaned), it was decided to fabricate new ductwork and coat it with the vinyl ester based material before installation to eliminate considerable down time which would occur with further cleaning and recoating of the existing ductwork. The amount of ductwork being fabricated and coated is that from the exit of the WSA Condenser to the third auxiliary burner.

The SO₂ Converter outlet expansion joint problems stem from the lack of availability of materials able to withstand the 800°F gas temperatures, high SO₃ concentrations, required movement, and sealing qualities. Because conventional expansion joint material must be left uninsulated, the adjoining steel temperature can fall below the acid dewpoint and suffer acid attack. This problem also occurred at the NEFO SNOX plant and was ultimately solved by use of an air purged joint. A small quantity of hot air from the WSA Condenser is employed for this purpose at NEFO and the same design is being incorporated into the Niles SNOX plant.

Problems with the rotating equipment (flue gas, cooling air, and ammonia dilution air fans) have also been encountered and were described in previous reports.^[1,2] These problems were not process related. A lube oil skid has been installed on the flue gas fan bearings, and the cooling air fan bearings have been reworked including shaft modifications.

TEST PROGRAM AND RESULTS

In order to demonstrate and evaluate the performance of the SNOX process during the Clean Coal Technology Program, general operating data is being collected and parametric tests conducted to characterize the process and equipment. An outline of the plan is presented below along with a description of the status of the parametric testing program. The primary objectives for the SNOX

Demonstration Project are as follows:

- Demonstrate NO_x and SO₂ removals of 90 and 95%, respectively.
- Demonstrate the commercial quality of the product sulfuric acid.
- Satisfy all Environmental Monitoring Plan (EMP) requirements.
- Perform a technical and economic characterization of the technology.

The following secondary objectives are identified in order to fully establish a basis for the technical and economic evaluation of a commercial application of this technology.

1. Execute parametric test batteries on all major pieces of equipment.
 - Fabric Filter
 - SCR System
 - SO₂ Converter
 - WSA Condenser
 - Gas/Gas Heat Exchanger
 - Catalyst Screening Unit
2. Quantify process consumptions.
 - Power
 - Natural Gas
 - Catalysts
 - Cooling Water
 - Potable Water
 - Ammonia
3. Quantify process productions.
 - Sulfuric Acid
 - Heat
4. Quantify personnel requirements.
5. Evaluate all materials of construction.

All information required to monitor the general health and environmental performance of the SNOX plant is archived through the computerized Distributive Control System (DCS) at six minute intervals into a magnetic media data base. The specific parameters include such items as temperatures, pressures, flows, gaseous concentrations, etc; and comprise 56 different data points. Routine analyses of inputs and outputs of the process requiring manual sampling are also made and their results are fed into the Master Data Base. The following table lists the parameters that are tested, the analytical methods used, and the frequency of each test.

<u>Stream</u>	<u>Parameter</u>	<u>Method</u>	<u>Frequency</u>
Coal	H ₂ O, Ash, S, Btu/lb	Proximate	Daily
	C, H, N, O	Ultimate	Monthly
	Trace Elements (1)	(2)	Quarterly
	Cl, F	(2)	Quarterly
Product Acid	wt. %	Titration	Each Load
	Color	APHA Standards	Each Load
	Fe	(2)	Each Load
	Trace Elements (1)	(2)	Monthly
	Cl, F	(2)	Monthly
	SO ₂ , NO ₃ , NH ₄	(2)	Monthly
	SiO ₂	(2)	Monthly
Acid Dil. Water	Trace Elements (1)	(2)	Quarterly
	Cl, F	ISE (3) or IC (4)	Quarterly
	Alkalinity	Titration	Quarterly
	SO ₂ , NO ₃ , NH ₄	(2)	Quarterly
Flyash	Trace Elements (1)	(2)	Quarterly
Catalyst Siftings	Heavy Metals	EP Toxicity	Each Occurrence
	Heavy Metals	TCLP	Each Occurrence
	Trace Elements (1)	(2)	Each Occurrence

(1) Trace Elements defined as As, B, Cd, Cr, Cu, Fe, Hg, K, Mg, Mn, Na, Ni, Pb, Se, V, Zn.

(2) Best Available Method

(3) Ion Specific Electrode Method

(4) Ion Chromatography

Tests Completed

To initiate the SNOX system parametric testing program, a group of tests were conducted on the Niles Station Unit 2 boiler to characterize its gaseous and particulate emissions ahead of the existing electrostatic precipitator and also at the stack discharge. At both locations, tests have been conducted for:

- Flow, temperature, pressure;
- Particulate loading and size distribution;
- SO₂, SO₃, NO, NO₂, N₂O, O₂, CO₂, CO, H₂O, HCl, F, NH₃; and
- As, B, Cd, Cr, Cu, Fe, Hg, K, Mg, Mn, Na, Ni, Pb, Se, V, Zn.

Many tests for the SNOX system are designated to be conducted at three SNOX system loads - 75%, 100%, and 110% of design capacity. At this time, the following major tests and evaluations have been conducted:

- System venturi calibration
- Fabric filter characterization (in and out) for same items as Unit 2 testing
- Gas/gas heat exchanger pressure drop, temperature profiles, overall performance
- SCR inlet flow and temperature distribution, inlet/outlet NO_x and NH₃
- SO₂ catalyst beds temperatures and flow distribution
- WSA Condenser SO₂ and SO₃ outlet concentrations by compartment, as well as compartment flow, temperature, and O₂ concentration
- Simultaneous manual samples at the system inlet and outlet for SO₂ and NO_x
- Cleaning of the SO₂ catalyst and analysis of the siftings
- Materials/coatings evaluations

In addition to the demonstration test program, the Department of Energy has also sponsored a study of toxic emissions from the SNOX process during July of 1993. This program was conducted by Battelle and final results are expected to be issued in the third quarter of 1994.

Results

The cumulative SNOX plant operating time and corresponding acid production are shown in Figure 3. The system has operated for more than 7000 hours and has produced more than 5000 tons of commercial grade sulfuric acid.

Detailed information on results from the SNOX plant testing have been given in other technical reports.^[1,2] SO₂ removal, NO_x removal, and acid quality have all met or exceeded the goals of the demonstration. Sulfur dioxide removal in the SNOX process is controlled by the efficiency of the SO₂ to SO₃ oxidation which occurs as the flue gas passes through the catalyst beds. This efficiency is

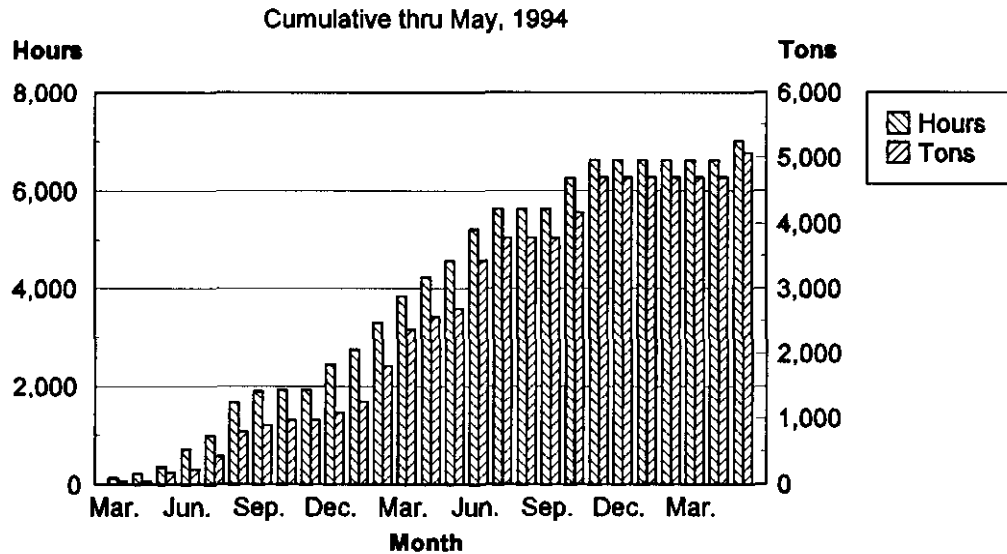


Figure 3
SNOX Plant Operating Time and Acid Production

controlled primarily by two factors - space velocity and bed temperature. During the test program, SO_2 removal has normally been in excess of 95% for inlet concentrations which average about 2000 ppm. Removal performance for a typical month is shown in Figure 4.

The SCR portion of the SNOX process, for reduction of nitrogen oxides, can operate at higher than typical ammonia stoichiometries due to its location ahead of the SO_2 catalyst beds. As was stated in the Process Description, excess ammonia is oxidized to nitrogen, water vapor, and a small amount of nitrogen oxide. Normal operating stoichiometries for the SCR system are in the range of 1.02 to 1.05, and system removal efficiency has averaged 94% for much of the operating time (shown in Figure 5). This is for inlet NO_x levels of approximately 500 to 700 ppm.

Sulfuric acid concentration and composition has also been excellent and has met or exceeded the requirements of the Federal Specification for Class 1 acid. ^[2] During design and construction of the SNOX plant at the Niles Station, arrangements were made with a sulfuric acid supplier to purchase and distribute the acid from the plant once operation began. The supplier, PVS Chemicals, is a large regional marketer and producer of sulfuric acid serving the industrial Midwest in New York, Ohio, Michigan and Illinois. This material has been sold primarily to industrial users such as the steel companies for pickling. Ohio Edison has also used a significant amount in their boiler water

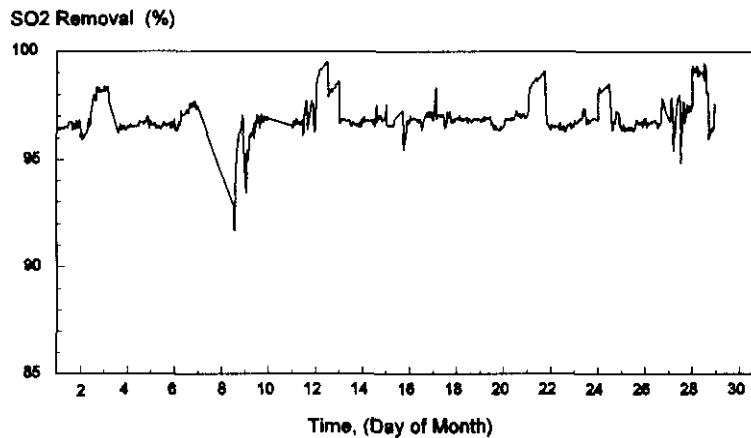


Figure 4
SO₂ Removal Efficiency - Typical Month

demineralizer systems throughout their plants.

With respect to the DOE sponsored air toxics testing at the Niles SNOX plant, preliminary results have been issued by Battelle for the study which was conducted from July 18-24, 1993.^[3] The substances measured within the SNOX process were as follows:

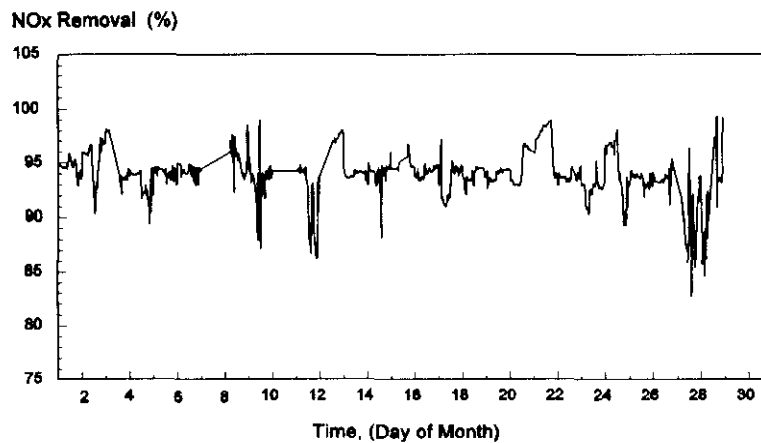


Figure 5
NO_x Removal Efficiency - Typical Month

- Five major and 16 trace elements, including mercury, chromium, cadmium, lead, selenium, arsenic, beryllium, and nickel
- Acids and corresponding anions (HCl, HF, chloride, fluoride, phosphate, sulfate)
- Ammonia and cyanide
- Elemental carbon
- Radionuclides
- Volatile organic compounds (VOC)
- Semi-volatile compounds (SVOC) including polynuclear aromatic hydrocarbons (PAH)
- Aldehydes

A large amount of data and samples were taken and analyzed during this test program. As was stated, the final report will be issued in the third quarter of 1994. For the majority of the species examined, and especially those that exist primarily as particulate at the SNOX fabric filter or SNOX outlet, removal across the system is very high. Because of the mechanism of sulfuric acid condensation in the WSA Condenser, any particulates remaining at this point act as nuclei for H_2SO_4 condensation and are captured in the acid. For volatile species, the WSA Condenser outlet temperature (200°F) is lower than conventional boiler outlet temperatures ($\approx 300^\circ F$) and should condense and capture more of the volatile species than a plant with only an ESP or fabric filter.

COMMERCIALIZATION STATUS

Since the inception of the project in the 1988-89 time frame, numerous requests for technical and cost information, budget proposals, and fixed-price proposals have been received from electric utility operators. Although no U.S. sales have been made at the present time, utility perception of the viability of the technology has been positive and has not been a deterrent to selling the process. Visitors to the SNOX Demonstration Plant in Niles, Ohio have been impressed with the system's simplicity, cleanliness, reliability, and overall particulate/ NO_x / SO_2 removal performance. Many of the interested parties have also visited the Danish 305 MW plant and were likewise impressed with its appearance and operation.

In addition to technical performance, minimal operating cost, resulting mainly from the lack of an SO_2 reagent, salable by-product, and recovery of thermal energy, has also been attractive to potential

customers. At a time when utilities are again looking at waste heat recovery, the SNOX process has a built-in heat recovery and integration scheme. Capital cost of the SNOX process, while higher than conventional technologies, still results in lower total operating cost (including O&M) for most situations.^[4]

Part of the reason for lack of a sale to date is related to the size of the actual market which occurred under Phase I compliance. This market was much smaller than predicted due to various reasons and therefore did not offer a large "pool" of potential flue gas cleaning sites. Also, the stringency of NO_x regulation under Phase I did not force utilities to select NO_x control processes with reduction capabilities superior to conventional technologies.

The condition of the sulfuric acid market in the U.S. has become "tighter" during the past 2-3 years and has necessitated that geographic locations be examined much more carefully to determine the marketability of acid in the "economically transportable" area. Information obtained about the industry has revealed that imports and "dumping" of sulfuric acid and sulfur in the U.S. has increased dramatically in these 2-3 years and poses an impediment to domestic clean coal technologies which produce sulfur or sulfuric acid instead of waste sludge.^[5]

In summary, the DOE SNOX Demonstration has clearly been a success with respect to its objectives of technical performance and verification of day-to-day commercial operation. The NO_x regulations which are forthcoming under Phase II will provide an impetus for the affected utilities to examine combined NO_x/SO_x control technologies such as the SNOX process. Air toxics control (along with PM 10) are likely to be important in the near future and the performance of the SNOX process in these areas will be a major selling point. Utilities are also re-examining the scenario of low sulfur coal, low NO_x burners and upgraded particulate collection due to the amount of boiler tuning that may be necessary for satisfactory operation. It is definitely less troublesome and may be more economic in the long term to employ post combustion NO_x control instead of furnace modifications.

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Current Progress with the Integrated Dry NO_x/SO₂ Emissions Control System

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ABSTRACT

The Integrated Dry NO_x/SO₂ Emissions Control System was installed at Public Service Company of Colorado's Arapahoe 4 generating station in 1992 in cooperation with the U.S. Department of Energy (DOE) and the Electric Power Research Institute (EPRI). This full-scale 100 MWe demonstration combines low-NO_x burners, overfire air, and selective non-catalytic reduction (SNCR) for NO_x control and dry sorbent injection (DSI) with humidification for SO₂ control. Operation and testing of the Integrated Dry NO_x/SO₂ Emissions Control System began in August 1992 and will continue through late 1994. Preliminary results of the NO_x control technologies show that the original system goal of 70% NO_x removal has been easily met and the combustion and SNCR system can achieve NO_x removals of up to 80% at full load. Duct injection of commercial calcium hydroxide has achieved a maximum SO₂ removal of nearly 40% while humidifying the flue gas to a 20°F approach to saturation. Sodium-based dry sorbent injection has provided short-term SO₂ removal of over 80% without the occurrence of a visible NO₂ plume.

INTRODUCTION

Beginning in the late 1980's Public Service Company of Colorado (PSCC) began retrofitting its wall and tangential coal-fired boilers located in the Denver Metropolitan area with low-NO_x burners. However, the company also operates seven top-fired boilers for which no previous NO_x reduction research had been completed. There are only a small number of top-fired boilers in operation in the United States, but these compact boilers generally have much higher NO_x emissions than the more common wall and tangential boilers. PSCC had also been investigating sodium-based dry sorbent injection for SO₂ control. Although PSCC installed the first permanent utility system in the United States, the technology needed further research to develop its commercial potential. After further research, PSCC submitted a proposal to the DOE to complete the Integrated Dry NO_x/SO₂ Emissions Control system as part of Round III of the Clean Coal Technology Program. Table 1 shows the participants involved in the project and their major responsibilities.

TABLE 1 - Project Participants

Participant	Function
Public Service Company of Colorado	Project Manager, Design, Construction, Funding
U.S. Department of Energy	Funding, Technical Assistance
Electric Power Research Institute	Funding, Technical Assistance
Babcock & Wilcox	Combustion Modifications and Humidification System Design, Supply, and Erection
Noell, Inc	Urea Injection System Design, Supply
Fossil Energy Research Corporation	Testing
Stone & Webster Engineering Corporation	General Engineering and Design
Western Research Institute	Waste Analysis and Research
Colorado School of Mines	Sodium Injection Process Research

UNIT DESCRIPTION

PSCC selected Arapahoe Unit 4 as the demonstration site for this project. The station has four top-fired boilers supplied by Babcock and Wilcox in the early 1950s. Arapahoe 4 is a nominal 100 MWe unit that began operation in 1955. The boiler fires low-sulfur (0.4%) Colorado bituminous coal as its main fuel source but also has 100% natural gas capability. While Arapahoe 4 is an older unit, having operated nearly 40 years, PSCC plans to operate it into the next century.

This small, turbulent boiler was an efficient coal combustor but it also generated high NO_x emissions. The baseline NO_x level for this boiler was approximately 1.10 lb/MMBtu. The pulverized coal was injected through 12 intertube burners located in the roof of the boiler as shown in Figure 1. The intertube burner is not comparable to the more common wall-fired burner. It consists of a splitter box that separates into 20 smaller nozzles that inject the coal and primary air mixture evenly across the furnace roof. Secondary air was injected beside the coal nozzles, and the system contained no adjustments to control the rate of secondary air and fuel mixing.

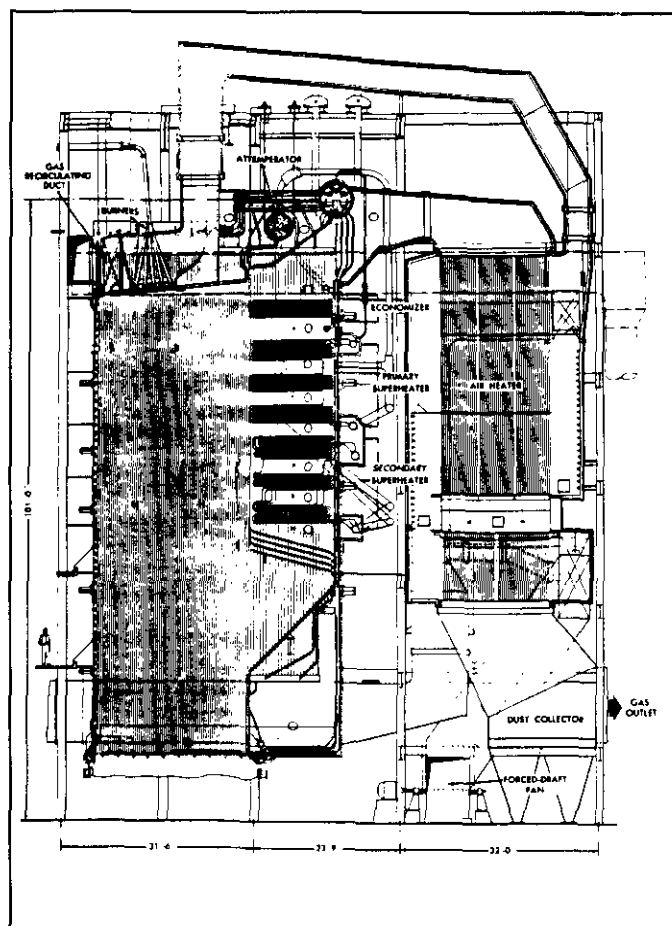


Figure 1 - Boiler Elevation

PROJECT DESCRIPTION

The Integrated Dry NO_x/SO_2 Emissions Control System combines five major control technologies to form an integrated system to control both NO_x and SO_2 emissions. The system uses low- NO_x burners, overfire air, and urea injection to reduce NO_x emissions, and dry sorbent injection using either sodium- or calcium-based reagents with humidification to control SO_2 emissions. The goal of the project is to reduce NO_x and SO_2 emissions by up to 70%. The combustion modifications were expected to reduce NO_x by 50%, and the SNCR system was expected to increase to total reduction to 70%. Dry Sorbent Injection was expected to provide 50% removal of the SO_2 emissions while using calcium-based reagents. Because sodium is much more reactive than calcium, it was expected to provide SO_2 removals of up to 70%. Figure 2 shows a simplified schematic of the Integrated Dry NO_x/SO_2 Emissions Control System at Arapahoe 4.

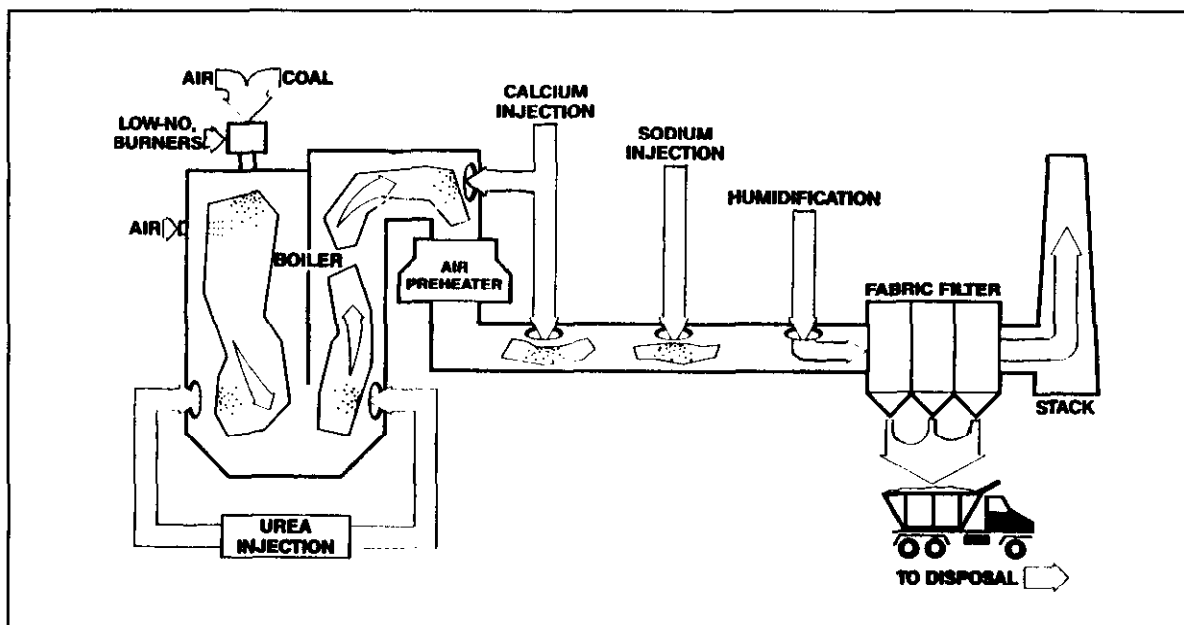


Figure 2 - Process Flow Diagram

The total estimated cost of this innovative demonstration project is estimated to be \$27,411,000. The project cost breakdown is shown in Table 2. Funding is being provided by the DOE (50.0%), PSCC (43.7%), and EPRI (6.3%). The DOE funding is being provided as a zero interest loan and is expected to be paid back from the proceeds obtained during commercialization of the technology over a 20-year period from the conclusion of the demonstration project.

Table 2 - Project Cost

Task	Estimated Cost
Pre-Award	\$358,000
Design	\$3,717,000
Equipment Procurement	\$8,445,000
Construction	\$8,296,000
Operations & Maintenance	\$6,595,000
TOTAL	\$27,411,000

Low-NO_x Burners

Babcock and Wilcox (B&W) was selected to provide the low-NO_x burners for the Arapahoe 4 project. B&W's DRB-XCL® (Dual Register Burner-a_Xially Controlled Low-NO_x) burner had been

successfully used to reduce NO_x emissions on wall-fired boilers but had never been used in a vertically-fired furnace. The burner has two main features that limit NO_x formation. The first feature is a sliding air damper. In many older burners, a single register is used to control both total secondary air flow to the burner and the rate of air/fuel mixing. The use of the sliding damper in the DRB-XCL® separates the functions and allows the secondary air flow to be controlled independently of the spin. The burner includes a 30-point pitot tube grid so that a relative indication of the secondary air flow at each burner is possible. The second feature of the burner is dual registers. The most important variable in the control of NO_x is the rate at which oxygen is mixed with the fuel. The ability to adjust both inner and outer registers provides more control over the rate of combustion and thus the amount of NO_x formed.

A low-NO_x retrofit on a top-fired unit is much more complex and much more expensive than modifications to most wall- or tangential-fired units. At Arapahoe Unit 4, the modifications required the replacement of all boiler roof tubes to provide the circular openings required for a conventional burner. The burners were placed in 4 rows of 3 burners. One major design problem of the retrofit was locating the secondary air ductwork, which originally entered the windbox at the rear of the furnace roof. The new burners required significantly more space than the intertube burners did, so there are now four burners where the secondary air duct was originally placed. Smaller ductwork was added to the furnace roof and the remaining combustion air was added through an abandoned gas recirculation duct that entered the front of the furnace.

Arapahoe 4 originally included the ability to fire 100% natural gas. While it uses coal as the main fuel, it occasionally uses natural gas to provide load when pulverizers or other equipment are out of service. Natural gas firing was maintained with the DRB-XCL® burners with a gas ring header at the tip of the burner.

Overfire Air

While low-NO_x burners alone have proven to be effective for reducing NO_x emissions, combustion staging can provide further reductions. Overfire air delays combustion by redirecting up to 28% of the secondary air downstream of the main combustion zone. As the initial combustion occurs at

lower stoichiometric ratios, less NO_x is formed. At Arapahoe 4, three B&W dual zone NO_x Ports were added to each side of the furnace approximately 20 feet below the boiler roof. These ports can inject up to 28% of the total combustion air through the furnace sidewalls. The NO_x ports separate the overfire air into two streams. The outer area of the port contains adjustable registers that can be used to spread the overfire air next to the wall. The center area of the port uses a sliding disk damper to control air flow. This core zone injects a high velocity jet across the furnace toward the division wall. This two-stage air injection allows for faster mixing and more equal distribution of the air and combustion gases in the furnace.

The NO_x ports are located on the two sides of the furnace in a small windbox. New ductwork was added that directs secondary air from the boiler roof to the overfire air windbox. Each duct that supplies the overfire air windboxes contains an opposed blade louver damper to control air flow. The ducts also contain a pitot tube grid with a flow straightener to measure total overfire air flow.

Selective Non-Catalytic Reduction

The purpose of the SNCR system at Arapahoe was to further reduce the final NO_x emissions obtained with the combustion modification so that the goal of 70% NO_x removal could be achieved. Urea was selected as the base chemical for the SNCR system, because urea, unlike either aqueous or anhydrous ammonia, is not a toxic chemical. Urea injection is a simple process. A liquid solution

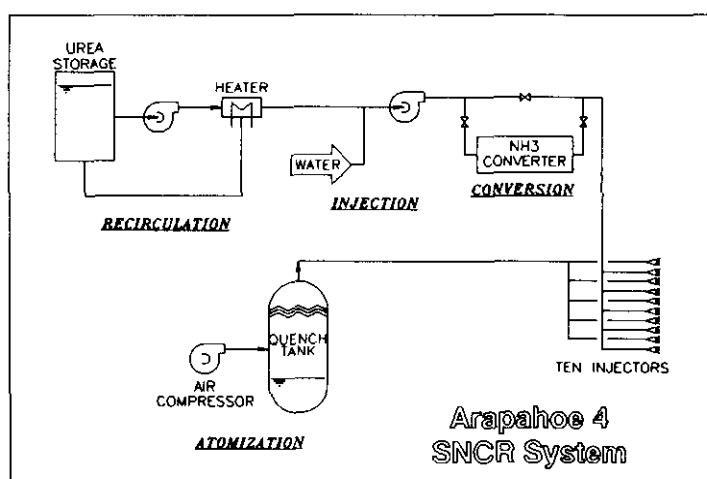


Figure 3 - SNCR Flow Diagram

of urea is injected into the boiler. Urea decomposes at approximately 1700 to 1900°F and then reacts with NO_x to form primarily nitrogen and water. The disadvantage of urea injection, as with any SNCR chemical, is that the process is very temperature sensitive. If the temperature is too high, some urea can be converted to NO_x . If the temperature is too low, more of the urea converts to NH_3 in a region that does not remove NO_x and becomes an unacceptable new pollutant. PSCC selected Noell,

Inc. to design and supply the urea-based SNCR system. Figure 3 shows a simplified flow diagram of the system at Arapahoe Unit 4.

During original testing of the urea-based SNCR system, it was found that NO_x reductions at low load were less than expected. A short-term test using aqueous ammonia achieved greater NO_x reduction than urea. Although ammonia was more effective than urea, it remained desirable to store urea due to safety concerns. A system was installed that allows on-line conversion of urea into ammonia compounds.

The SNCR system at Arapahoe Unit 4 uses Noell's proprietary dual fluid injection nozzles to distribute the chemical uniformly into the boiler. A centrifugal compressor is used to supply a large volume of medium pressure air to the injection nozzles to help atomize the solution and rapidly mix the chemical with the flue gas.

Dry Sorbent Injection

A combination of dry technologies is being demonstrated at Arapahoe 4 to reduce SO_2 emissions. PSCC designed and installed a dry sorbent injection system that can inject either calcium- or sodium-based reagents into the flue gas upstream of the fabric filter. Figure 4 shows a simplified flow diagram of the equipment. The reagent is fed through a volumetric feeder into a pneumatic conveying system. The air and material then pass through a pulverizer where the material can be pulverized to approximately 90% passing 400 U.S. Standard mesh. The material is then conveyed to the duct and evenly injected into the flue gas. A bypass can be installed to convey calcium hydroxide into the boiler upstream of the economizer in a region where the flue gas temperature is approximately 1000°F . After the original testing was completed that suggested the duct flue gas temperature was too low for effective SO_2 removal with sodium bicarbonate, the dry injection system was modified to allow injection of sodium-based compounds at the entrance to the air heater where the flue gas temperature is approximately 600°F .

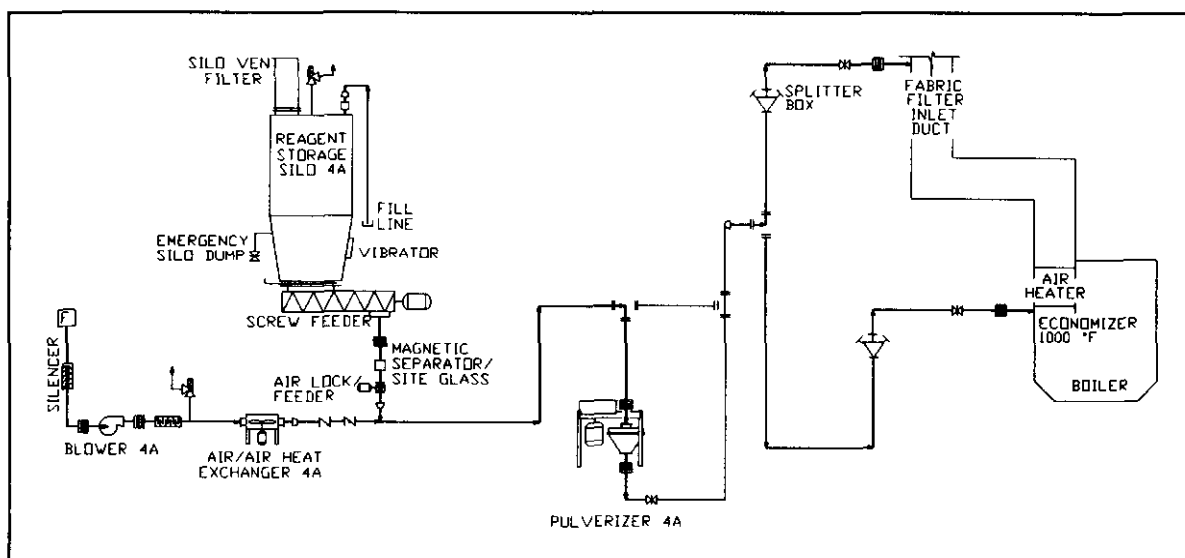


Figure 4 - Dry Sorbent Injection Flow Diagram

While significant SO₂ reductions can be achieved with sodium-based reagent, calcium hydroxide is less reactive. To improve SO₂ removal with calcium hydroxide, a humidification system has been installed. The system was designed by B&W and includes 84 I-Jet humidification nozzles to inject up to 80 gpm of water into the flue gas ductwork. The humidifier is located approximately 100 feet ahead of the fabric filter and there is no bypass duct. Although the system is designed to achieve a 20°F approach to saturation, it was not expected to operate the humidifier below a 40°F approach to saturation to protect the fabric filter.

Balance of Plant

Besides the major environmental equipment, the project also included required upgrades to the existing plant. Arapahoe 4 originally used a Bailey pneumatic control system with limited controls for burner management. Due to the complexity of the retrofit, a new distributed control system was required to control the boiler and other pollution control equipment added as part of the project. The flyash collection system was also converted from a wet to a dry collection system to allow dry collection of the ash and injection waste products. A Continuous Emissions Monitor (CEM) system was installed at Arapahoe Unit 4 to collect data for the extensive test program. This monitor allows measurements of N₂O, NH₃, NO₂, and H₂O in addition to the more common pollutant measurements.

PROJECT SCHEDULE

The Integrated Dry NO_x/SO₂ Emissions Control System began with its selection by the DOE in December 1989. Negotiations for the project were completed with approval of the Cooperative Agreement on March 11, 1991. Construction began in July 1991 and was completed in August 1992. The test program began in August 1992 and all low sulfur coal testing is scheduled for completion in June 1994. A ten day test of the integrated system using a high sulfur (2.5%) coal has been delayed until September 1994 while the Colorado State regulations are being changed to allow for the increased SO₂ emissions that will occur during this testing. Project completion is currently scheduled in November 1994, although an extension may be required due to the delay in the high sulfur coal testing. Table 3 shows the project schedule.

Table 3 Arapahoe 4 Project Schedule

	1989	1990	1991	1992	1993	1994
Project Selection	▲					
Cooperative Agreement Signed			▲			
Construction			▲	→		
Baseline Testing			▲	→		
SNCR Testing/Original Burners			▲	→		
Low NO _x Burner Startup				▲		
Combustion Mods Testing				▲	→	
SNCR Testing					▲	→
Calcium-Based DSI Testing					▲	→
Sodium-Based DSI Testing					▲	→
Air Toxics Testing				▲	▲	▲
Integrated Testing/Low Sulfur Coal						▲
Integrated Testing /High Sulfur Coal						▲
Final Report						▲
Project Completion						▲

PRELIMINARY RESULTS

Fossil Energy Research Corporation (FERCo) of Laguna Hills, California, was selected to perform all testing of the Integrated Dry NO_x/SO₂ Emissions Control System. The test program is nearing completion and the individual testing of the low-NO_x burners, overfire air, urea injection, calcium duct injection, calcium economizer injection, and sodium injection has been completed. Testing of the complete integrated system while firing low-sulfur coal is in progress. In addition to efficiency and

emissions measurements, four tests were conducted to determine baseline and removal capabilities of the system for many common air toxic emissions. Previous papers concentrated on the NO_x removal capability of the system, so this paper briefly reviews the NO_x data and concentrates on the SO₂ removal capability of the Integrated Dry NO_x/SO₂ Emissions Control System.

Combustion Modifications

Figure 5 shows the original baseline NO_x emissions compared to the tuned post-combustion retrofit emissions. Baseline NO_x emissions for the unit before the retrofit were nearly uniform across the load range at approximately 800 ppmc (Corrected to 3% O₂, dry) or about 1.10 lb/MMBtu. The combination of low-NO_x burners and overfire air greatly reduced NO_x emissions to under 300 ppmc. NO_x reduction varies from 63 to 69% across the

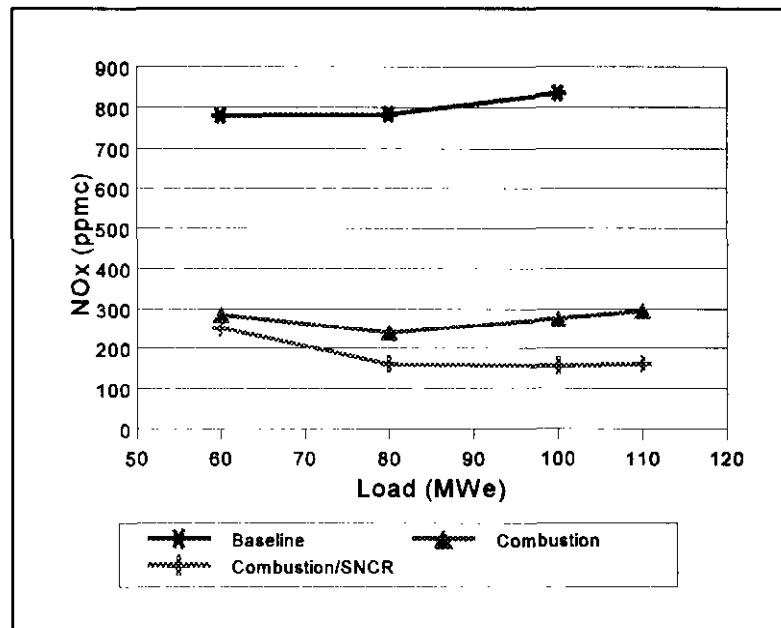


Figure 5 NO_x Emissions

load range. The post-retrofit NO_x emissions are shown with the unit operating with the maximum overfire air at all loads. With maximum overfire air, approximately 25% to 30% of the total combustion air is introduced through the overfire air ports.

These significant NO_x reductions were obtained without increases in carbon monoxide (CO) or flyash unburned carbon emissions. Unexpectedly, testing at Arapahoe found that at higher loads the high quantities of overfire air actually decreased carbon and CO emissions. It is believed that the additional mixing that occurs on a top-fired boiler at high overfire air flows caused these decreases.

All data obtained from the burner and overfire air system indicate that most of the NO_x reduction is due to the low- NO_x burners and not the overfire air system. However, due to the large amount of cooling air (nearly 15% of the total air flow) needed to maintain the overfire air port metal temperature, it was not possible to test the combustion modifications with no overfire air. The lower than expected NO_x reduction with overfire air may be due to insufficient distance (approximately 20 feet) between the burners and the overfire air ports. If additional time were available for combustion to occur at the lower stoichiometric ratios, the overfire air system may be more effective.

Selective Non-Catalytic Reduction Testing

Figure 5 also shows the NO_x emissions attainable when operating the urea-based SNCR at urea injection rates that limit NH_3 slip at the fabric filter inlet to 10 ppm. This corresponds to a NO_x reduction from 11 to 45% over the load range. Thus, the combined NO_x reduction from the combustion and SNCR system ranges from 66 to 82% over the load range.

The urea-based SNCR system can achieve reasonable NO_x removal at higher loads, but it was not very effective at low loads. The original design of the SNCR system included two different injection locations. The plan was to use the first injection location, located in an area of the boiler with higher flue gas temperatures, at low loads, and then switch to the second injection location, located in an area of the boiler with lower flue gas

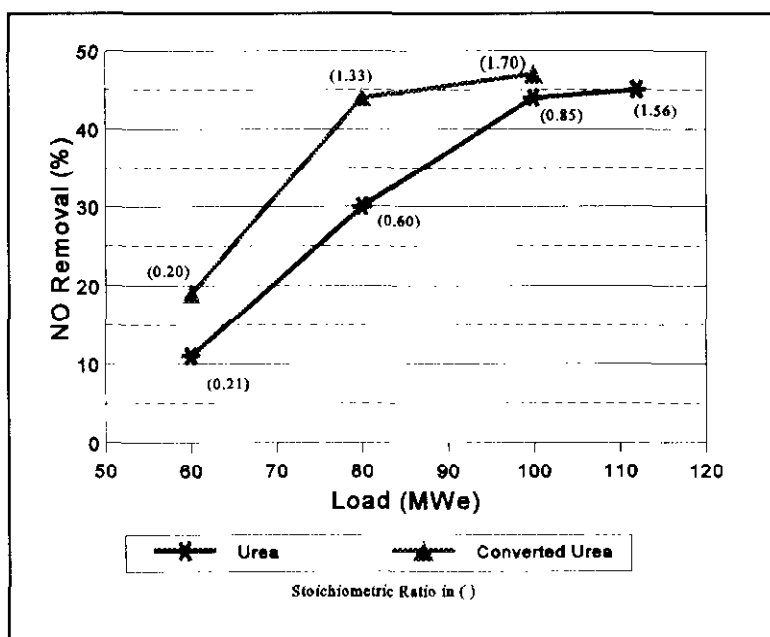


Figure 6 SNCR NO Removal

temperatures, at high loads. However, testing showed that the flue gas temperature at the second location was either too cool or the residence times were too short for effective NO_x removal. Thus, all testing was limited to a single injection location. To increase low-load NO_x removal, the system

was modified with an on-line ammonia conversion system. Ammonia compounds react faster than urea and in a lower temperature window. Figure 6 shows that when injected into the same location, urea converted to ammonia compounds provided higher NO_x removal than urea, when compared on an equal ammonia slip basis. However, the increased NO_x removals required an increased chemical injection rate of 67 to 133%. In summary, the ammonia conversion system provided the most efficient NO_x removal at loads less than approximately 70MWe while urea was more effective at loads above 70MWe. The project is currently considering adding a new injection location in an area of the boiler with hotter flue gas to increase NO_x removal when using urea reagent at low loads.

In addition to creating ammonia emissions, SNCR using either urea or urea converted to ammonia-based compounds also increases nitrous oxide (N_2O) emissions. While injecting urea, the increase in N_2O varied from 20 to 35% of the total NO removed, depending on load and urea injection rate. The increased N_2O emissions while injecting converted urea were much less and varied from 3 to 10% of the total NO removed under similar operating conditions.

Dry Sorbent Injection Testing/Calcium-Based Economizer Injection

SO_2 removal has been less than expected during calcium hydroxide injection at the economizer. Pilot-scale testing near 1000°F has shown the potential for SO_2 removals near 50%. [1] At Arapahoe, initial testing at a stoichiometry of 2.0 without humidification resulted in SO_2 removals in the range of 5 to 8%. It was found that distribution of the sorbent was very poor, and only approximately 1/3 of the flue gas was being treated. Although SO_2 removals of slightly above 30% were obtained in the area of treatment, the local stoichiometry in this area was estimated at 6.0. New nozzles that increased reagent distribution were installed on one-half of the boiler. With the improved distribution, SO_2 removal was nearly doubled to 15% at a stoichiometry of 2. Although distribution of the calcium reagent is far from perfect, it appears that high levels of SO_2 removal are not possible at Arapahoe 4 using the current $\text{Ca}(\text{OH})_2$ material; even in areas with high stoichiometries. Samples of the reagent have been analyzed for surface area and particle size; both parameters being important for economizer injection. The BET surface area of the $\text{Ca}(\text{OH})_2$ is 14.8 m^2/gm and the mass mean particle size diameter is 2.7 microns (determined by sedimentation). The relatively low surface area of the $\text{Ca}(\text{OH})_2$ may be contributing to the low SO_2 removals obtained with economizer injection.

Operation of the humidification system during economizer injection increased SO₂ removal by only 3 to 4%. An analysis of a sample obtained of the sorbent/fly ash mixture collected at the boiler exit found that approximately 63% of the calcium in the sample was CaCO₃ and only 32% of the calcium was Ca(OH)₂. As humidification is only effective with Ca(OH)₂, the low levels of Ca(OH)₂ available may explain the small additional SO₂ removal possible with humidification.

Dry Sorbent Injection Testing/Calcium-Based Duct Injection

Higher SO₂ removal was possible with duct injection of calcium hydroxide and humidification as shown in Figure 7. The data was collected at loads from 60 to 110MWe, but no correlation of SO₂ removal and load could be found. As expected, the strongest correlation occurred with the flue gas approach to adiabatic saturation temperature. A marked improvement in SO₂ removal was noted at an approach to saturation temperature of

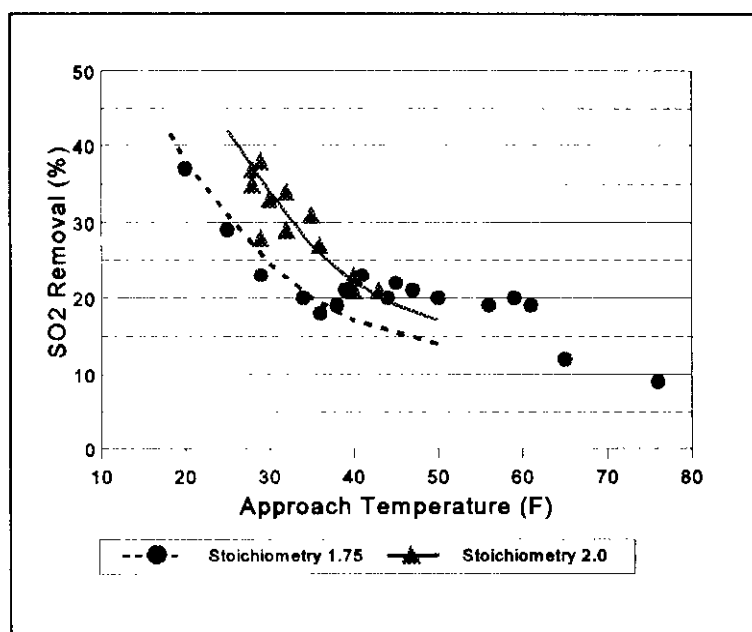


Figure 7 Calcium Duct Injection

approximately 45°F. As Arapahoe 4 uses a fabric filter dust collector for particulate control, it was not originally planned to reach approach temperatures below 45°F, but SO₂ removal was significantly below the goal of 50% removal. Monitoring of the ash/reagent dropout in the ductwork showed only minimal buildup and no fabric filter operational problems occurred, so it was decided to further decrease the approach to saturation temperature. At a 20°F approach temperature, nearly 40% SO₂ removal was obtained. Immediately after this test, problems developed with the dry flyash transport system, and it is suspected that the low approach temperature contributed to this problem. It was decided to limit testing to a 30°F approach temperature. At the end of the calcium test program after a short period of 24 hour/day testing during load following operation, fabric filter pressure drop significantly increased. Upon further investigation, a hard ash cake was found on the fabric filter

bags that could not be cleaned during normal reverse air cleaning. Fabric filter bag weights had increased by approximately 50% from pre-humidification testing. The heavy ash cakes were caused by the humidification system, but it was not possible to determine if the problem was caused by operation at a 30°F approach temperature or a short-excursion to a lower approach temperature caused by a rapid load drop. All bags were manually cleaned and reinstalled, and no permanent bag damage has been noticed.

Dry Sorbent Injection Testing/Sodium-Based Injection

Sodium-based reagents are much more reactive than calcium-based sorbents and can obtain significantly higher SO₂ removals during dry injection. Figure 8 shows the SO₂ removal for dry sorbent injection for sodium bicarbonate and sodium sesquicarbonate. Sodium bicarbonate provided the highest SO₂ removal and was also the most efficient reagent.

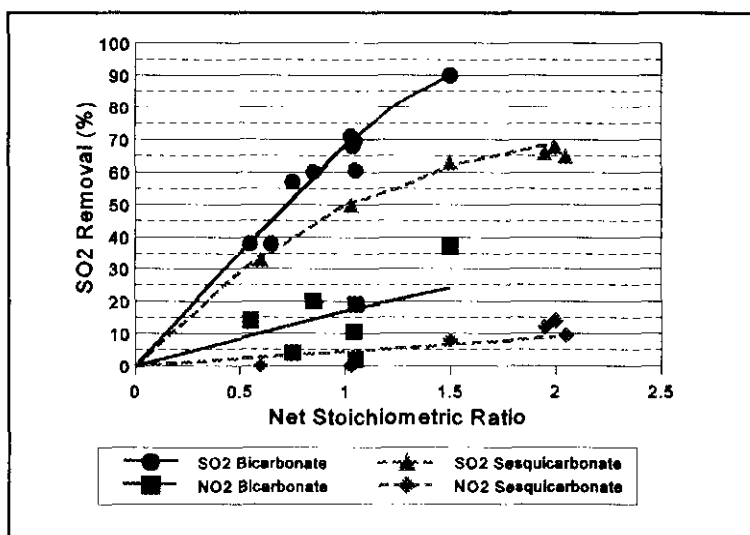


Figure 8 Sodium Duct Injection

A major disadvantage of sodium-based injection is that it converts some existing NO in the flue gas to NO₂. During the conversion process a small amount, 5 to 15%, of the total NO_x is removed. However, the net NO₂ exiting the stack is increased. While NO is a colorless gas, small quantities of the brown/orange NO₂ can cause a visible plume to develop. The chemistry of the conversion is not well understood but it is generally accepted that NO₂ increases as SO₂ removal increases. Figure 8 shows that NO₂ emissions are generally higher with sodium bicarbonate, although a significant amount of data scatter exists. The threshold NO₂ that forms a visible plume is site specific; at Arapahoe a visible plume appears when NO₂ concentrations reach 30 - 35 ppm.

While NO_2 emissions generally increase as injection level increases, other variables are also important. Figure 9 shows SO_2 removal and NO_2 emissions for each of the twelve compartments of the Arapahoe 4 fabric filter. The fabric filter is arranged in two rows of six compartments designated W1-W6 and E1-E6. The flue gas enters through a central duct between the rows and enters W1 and E1 first. All data were obtained while injecting sodium

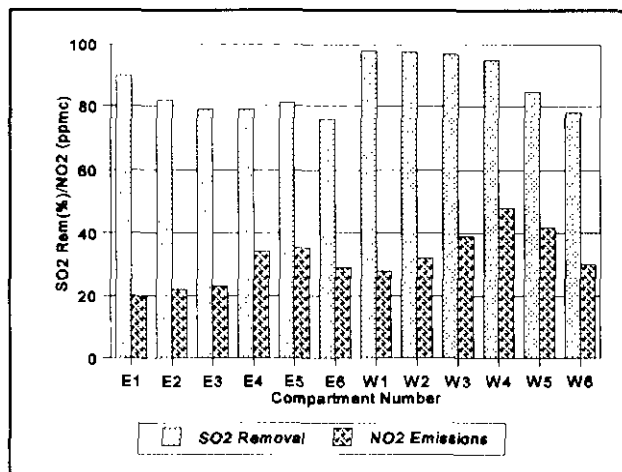


Figure 9 Compartment SO_2 & NO_2

bicarbonate at an NSR of 1.5 for an overall SO_2 removal of 89% and an average NO_2 emission of 32 ppmc. The data indicate that more SO_2 removal is obtained on the west half of the fabric filter and in the front compartments. The front compartments have the highest particulate loadings at Arapahoe 4. NO_2 emissions do not directly follow the SO_2 removal and the lowest emissions occur in the first two compartments, although these compartments (W1 and E1) received the greatest SO_2 removal for their respective rows. The reasons for the variations in NO_2 are not yet understood, but further testing and research are in progress that may help answer these questions.

Flue gas temperature at the fabric filter inlet duct at Arapahoe varies from 250 to 280°F. The dry sorbent injection system at Arapahoe was originally designed to use only duct injection before the fabric filter. However, initial testing with sodium bicarbonate showed that SO_2 removal was erratic. Up to ten hours was required for the SO_2 removal to stabilize and SO_2 removal dropped

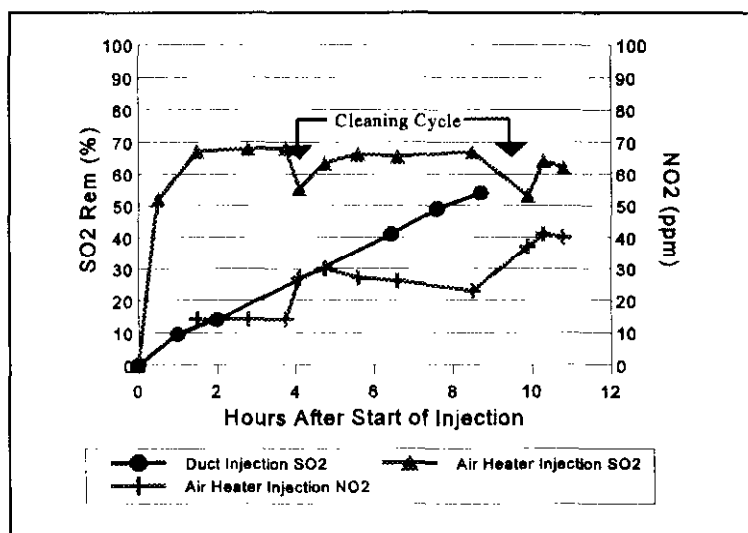


Figure 10 Sodium Bicarbonate SO_2

significantly during fabric filter cleaning cycles. The DSI system was modified to inject sodium sorbents at the air heater inlet where the flue gas temperature is approximately 600°F. Figure 10 shows SO₂ versus time for duct and air heater injection of sodium bicarbonate at an NSR of 1.0. During air heater injection, SO₂ removal leveled in slightly over one hour. But it did not stabilize in 8 hours during duct injection. It is believed that at the low flue gas temperatures, the sodium bicarbonate requires many hours to decompose and thus react with the SO₂.

Figure 10 also shows stack NO₂ emissions during air heater injection of sodium bicarbonate. NO₂ emissions increase fairly rapidly, but a significant increase is seen each time the fabric filter is cleaned. The NO₂ emissions then gradually decreased after the initial NO₂ spike. The data appear to indicate that either the dust cake absorbs or reacts with the NO₂ and reduces the net emissions. Further study will be required to confirm this theory.

Integrated Testing

It was originally projected that concurrent operation of the sodium-based dry sorbent injection system and the urea system would interact synergistically and reduce the negative effects of both systems. Testing of the integrated system continues, but preliminary indications are that both NH₃ emissions generated by urea injection and NO₂ emissions created from sodium injection are reduced when both systems are in operation. Figure 11 shows a plot of NO₂ emissions versus SO₂ removal for sodium bicarbonate both with and without concurrent urea injection. While there is significant data scatter, concurrent sodium/urea injection appears to result in lower NO₂ emissions. The data shows hourly averages of NO₂ and SO₂ removal obtained during 24 hour-per-day testing. Only data

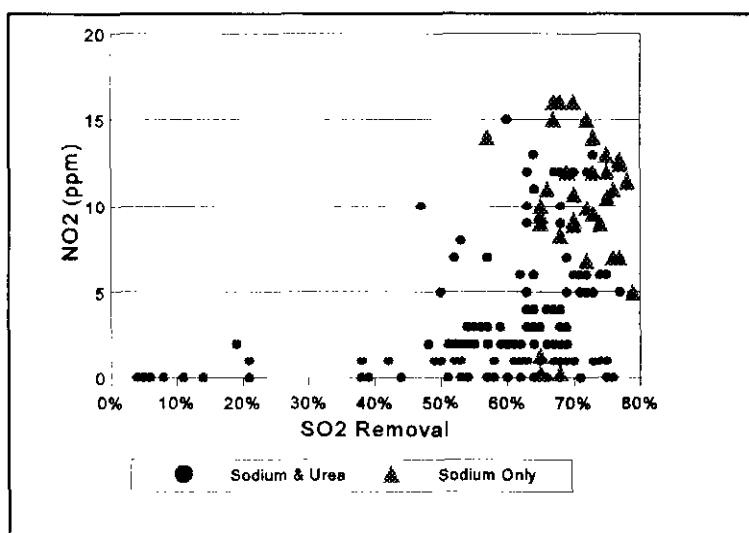


Figure 11 Integrated NO₂ Emissions

obtained two hours after a fabric filter cleaning cycle is plotted. Figure 12 shows the stack NH_3 emissions compared to NH_3 emissions at the air heater exit. The plot shows two important points. First, in all cases the stack NH_3 emissions were lower when the dry sodium injection system was in operation. Second, stack NH_3 emissions were always significantly

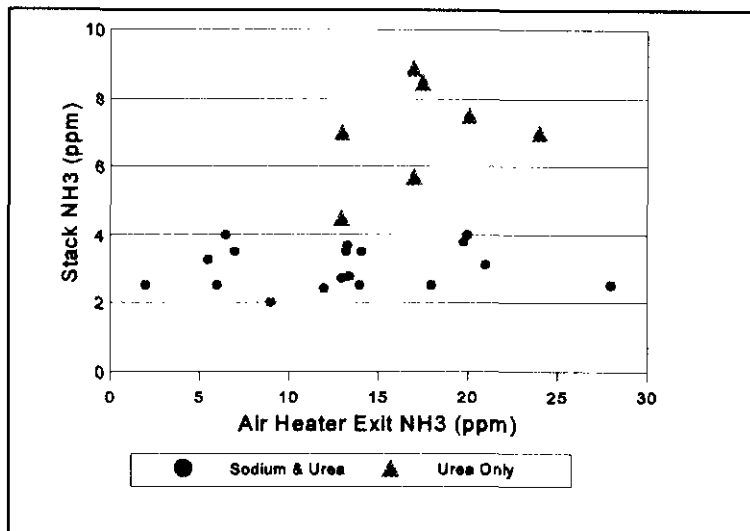


Figure 12 Stack/Air Heater Exit NH_3

lower than the NH_3 emissions at the air heater exit. The majority of the initial testing with the SNCR system collected data only at the air heater exit as the stack took many hours at constant NH_3 slip to stabilize. All the plotted data were taken during testing performed 24 hours-per-day, during which both load and the urea injection rate were constantly changing. Under these operating conditions, it would not be expected to arrive at stabilized conditions.

Air Toxics Testing

The project also includes a comprehensive investigation into many potential air toxic emissions. The two goals of this testing were (1) to determine a baseline value for a utility boiler firing a Western coal and using a fabric filter for particulate control and (2) to determine any effects of the Integrated Dry NO_x/SO_2 Emissions Control System. The air toxics test program sampled for trace metals, acid-forming anions, volatile organic compounds, semi-volatile organic compounds, dioxins and furans, and nitrogen compounds. Not all data have been analyzed but preliminary results are available from the baseline and SNCR testing. As expected, the fabric filter was very effective at capturing particulates. Overall particulate removal was greater than 99.96%. FFDC removal of all trace metals sampled averaged over 96.9%. Mercury removal had the lowest capture efficiency of 78%. Acid-forming anion emissions were low due to the low value of these anions in the coal used on this unit. Emissions of polycyclic aromatic hydrocarbons (PAHs) were very low and none of the carcinogenic PAH compounds were measured above the detection limit. Due to the very low

emissions, PAHs were only measured during the baseline testing. Radionuclides were also measured during the baseline testing, but only two radionuclides were measured above their detection limit and it is believed these values are not source related.

CONCLUSIONS

Public Service Company of Colorado, in cooperation with the U.S. Department of Energy and the Electric Power Research Institute, has installed the Integrated Dry NO_x/SO₂ Emissions Control System. The system has been in operation for over two years and preliminary conclusions are as follows:

- NO_x reduction during baseload operation of the unit with the low-NO_x burners and overfire air ranges from 63 to 69% with no increase in unburned flyash carbon or CO emissions.
- It is believed that the low-NO_x burners provided most of the NO_x reduction, however, due to cooling air requirements, it was not possible to test the system without overfire air.
- Urea injection allows an additional 11 to 45% NO_x removal with an ammonia slip of 10 ppm at the fabric filter inlet. This increases total system NO_x reduction to greater than 80% at full load, significantly exceeding the project goal of 70%.
- Higher NO_x reduction is possible using ammonia as the SNCR chemical, but significantly higher stoichiometric ratios are required at loads above 70 MWe.
- N₂O generation is a potential concern with urea injection but was greatly reduced when ammonia compounds were injected.
- SO₂ removal with the calcium-based dry sorbent injection into the boiler at approximately 1000°F flue gas temperature was disappointing with less than 10% removal possible.
- SO₂ removal with the calcium-based dry sorbent injection into the fabric filter duct has been less than expected with a maximum short term removal rate approaching 40%.
- Sodium bicarbonate injection before the air heater has been very effective with short term SO₂ removals of over 80% possible. Longer term testing has demonstrated removal near 70% at an approximate stoichiometric ratio of 1.0.
- NO₂ emissions are generally higher when using sodium bicarbonate than when using sodium sesquicarbonate. The NO₂ generated during sodium-based injection is related to SO₂ removal and the cleaning cycle of the fabric filter, but all factors important to NO₂ generation are not fully understood.

- The integration of urea-based SNCR and sodium-based dry sorbent injection appears to reduce the net stack NH_3 and NO_2 emissions. Further testing is ongoing to confirm the amount of reduction that occurs due to the integration of the two technologies.
- The Arapahoe 4 fabric filter is very effective at removing particulates and particulate-based air toxics. Overall trace metals removal was over 97% in two tests. PAH's and radionuclide emissions were at or very near the detection limit for the sampling.

DISCLAIMER

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THE NOXSO CLEAN COAL PROJECT

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ABSTRACT

The NOXSO process is a waste-free, dry, post-combustion flue gas treatment technology which uses a regenerable sorbent to simultaneously adsorb sulfur dioxide (SO_2) and nitrogen oxides (NO_x) from the flue gas of a coal-fired utility boiler. Removal efficiencies as high as 99+ % for SO_2 and 95% for NO_x were demonstrated during more than 7000 hours of pilot-plant testing. The SO_2 is converted to a saleable sulfur by-product and the NO_x is converted to nitrogen and oxygen. The process is suited for either retrofit or new facility applications.

The NOXSO Clean Coal Technology Project will demonstrate the NOXSO process on a commercial scale. The \$66 million project is co-funded by the U.S. Department of Energy (DOE) under round III of the Clean Coal Technology program. The DOE manages the project through the Pittsburgh Energy Technology Center (PETC). The NOXSO process, plant general arrangement, economics, and project schedule are described in this paper.

INTRODUCTION

The NOXSO process is a waste-free, dry, post-combustion flue gas treatment technology which uses a regenerable sorbent to simultaneously adsorb sulfur dioxide (SO_2) and nitrogen oxides (NO_x) from the flue gas of a coal-fired utility boiler. In the process, the SO_2 is converted to a sulfur by-product (elemental sulfur, sulfuric acid, or liquid SO_2) and the NO_x is converted to nitrogen and oxygen. Based on pilot-plant results, the process can economically remove 95% of the acid rain precursor gases from the flue gas stream in a retrofit or new facility.

Process development began in 1979 with laboratory-scale tests and progressed to pre-pilot-scale tests (3/4-MW) and a life-cycle test. Each of these test programs [1,2,3] has provided data necessary for the process design. Tests of the NO_x recycle concept, which is inherent to the NOXSO process, have been conducted on small boilers at PETC and at the Babcock & Wilcox (B&W) Research Center in Alliance, Ohio [4]. A 5-MW Proof-of-Concept (POC) pilot-plant test at Ohio Edison's Toronto Plant in Toronto, Ohio, was recently completed [5]. The Clean Coal Project is currently in the project definition phase incorporating recently obtained pilot-plant data into a commercial-scale design. Potential host sites are presently being evaluated.

The objective of the NOXSO Clean Coal Technology Project is to demonstrate the NOXSO process on a commercial scale. At the completion of this project, economic and operating data will be available to assist utilities in making decisions regarding the choice of flue gas cleanup technology.

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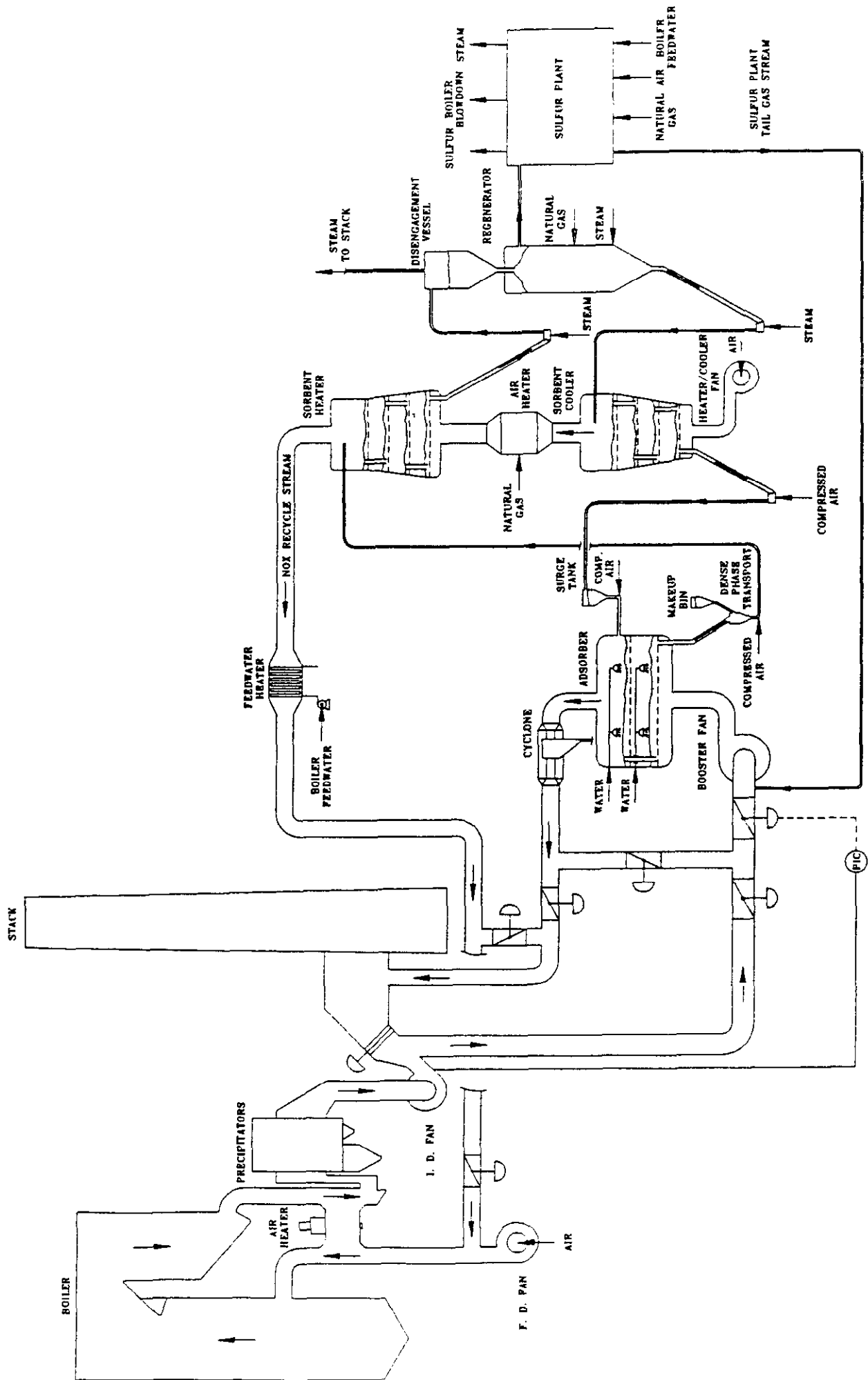


Figure 1. Process Flow Diagram

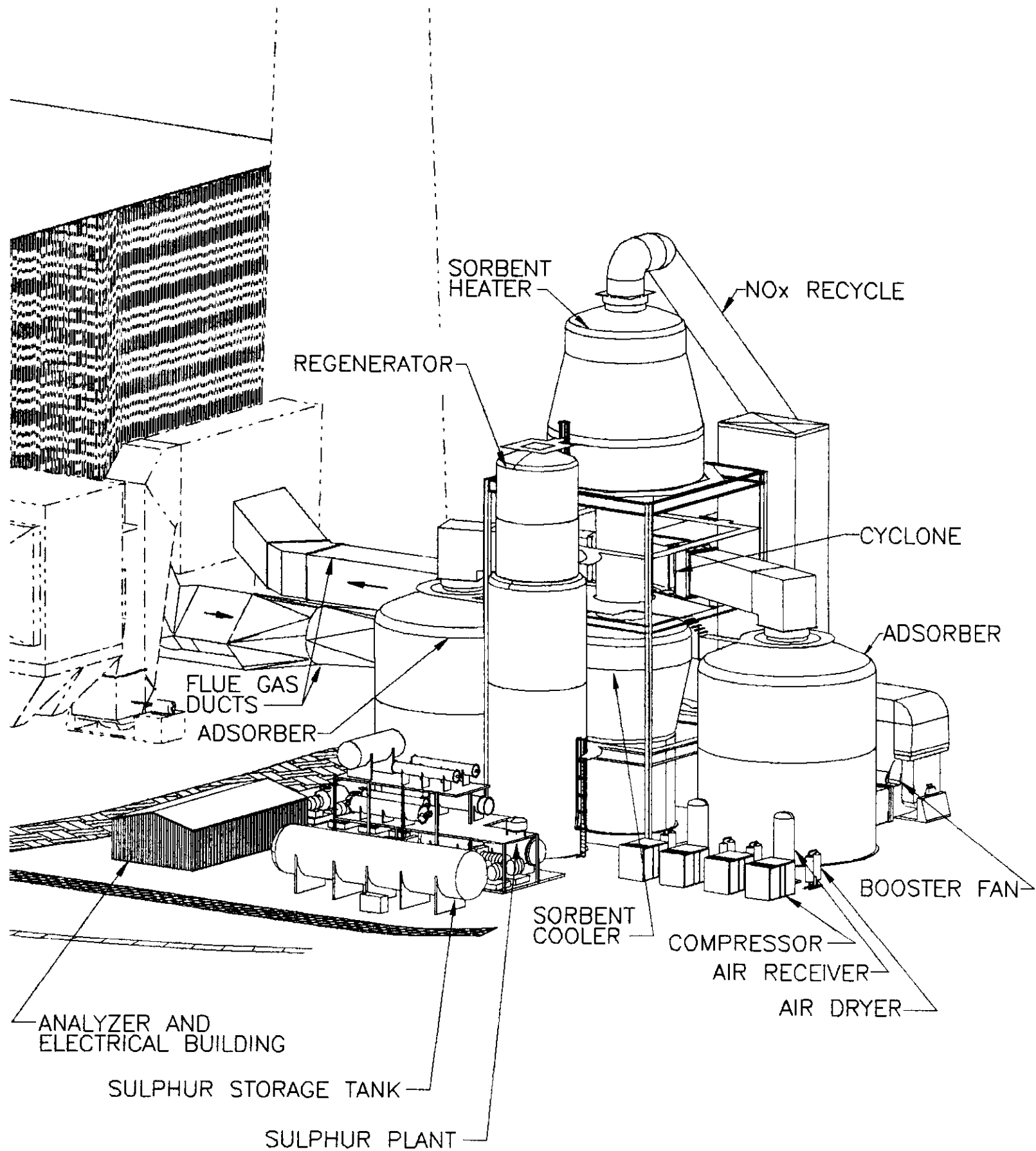


Figure 2. NOXSO Plant Arrangement

The two NOXSO adsorption trains, consisting of a booster fan, adsorber vessel, cyclone separator, and interconnecting duct work, each have isolation dampers that will allow either train to be operated independently from the other. In addition, each train has a bypass line that will allow the NOXSO system to operate in a hot standby mode when flue gas is not available. In the standby mode, heat is added to the gas from the mechanical energy of the booster fans. A bleed-off stream is used to control temperature in this mode of operation with ambient air providing the required makeup. This standby mode also allows the system to be brought up to operating temperature during a cold start-up prior to the introduction of flue gas. This pre-heating of the system prevents acid condensate from forming which could happen if flue gas were introduced into cold duct work. The adsorbers and associated duct work are constructed from carbon steel. Flue gas temperature is maintained above the acid dewpoint until it reaches the first adsorber bed. Once in the bed, SO_3 , SO_2 , and NO_x are adsorbed, reducing the dewpoint to below the bed operating temperature. In this manner, exotic materials of construction are avoided.

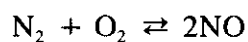
The temperature of the adsorber beds is controlled at 250°F (121°C) by spraying water directly into each bed. Using this cooling technique prevents the formation of acid in the system. The water spray volume is small compared to the flue gas volume (approximately 2.5%), and the water evaporates instantaneously in the flue gas stream flowing through the fluid beds. An array of nozzles is used to achieve complete coverage of the bed. Temperature is a key parameter relating to NO_x removal efficiency with lower temperature promoting higher removals.

The remaining portion of the NOXSO system is used to regenerate the sorbent and provide ultimate disposition of the adsorbed NO_x and SO_2 . Sorbent from the adsorbers is pneumatically conveyed in dense-phase transport systems to the sorbent heater. The sorbent heater is a four-stage fluidized-bed reactor that is used to raise the sorbent temperature to 1150°F (621°C) for regeneration purposes. The vessel itself is tapered so that the variable cross-sectional area on each stage will account for the change in gas volume due to temperature and pressure variations within the vessel, thereby maintaining a constant

velocity of 3 ft/s (0.91 m/s) on each stage. The average diameter of the sorbent heater is 30 ft (9.1-m). The vessel is made of 304H stainless steel.

During the heating process, adsorbed NO_x is driven from the sorbent and exits the vessel in the sorbent heater off-gas, hereafter referred to as the NO_x recycle stream. The NO_x recycle stream is at a temperature of 445°F (229°C). Heat is recovered from this stream by heating a slipstream of the power-plant's boiler feedwater (BFW). Feedwater will be taken from one of the low pressure feedwater heaters and returned to an appropriate location based on temperature considerations. If the power plant is boiler limited, some of the extraction steam previously used to heat BFW will now be available to generate additional electricity, partially off-setting the electrical power consumption of the NOXSO process. If the power plant is not boiler limited, the thermal energy recovered from the NO_x recycle stream will reduce the power-plant coal feed rate resulting in a fuel savings. The economic analysis discussed later in this paper assumes the power plant is boiler limited. After heating a slipstream of BFW, the temperature of the NO_x recycle stream is 150°F (66°C). This stream is then returned to the power-plant's combustion air system. Because the NO_x recycle stream will replace approximately 30% of the power-plant's combustion air stream, the power consumption of the combustion air forced draft fans is decreased and the amount of extraction steam required to preheat the combustion air prior to the forced draft fans is also reduced. Both produce energy credits for the operation of the NOXSO process.

A portion of the NO_x returned to the combustion air stream by the NO_x recycle stream is destroyed in the boiler. NO_x destruction is achieved by two mechanisms. The first mechanism takes advantage of the NO_x formation reaction equilibrium. By injecting NO_x into the combustion chamber, the NO_x concentration is increased above the equilibrium value. NO_x formation is thereby suppressed in the combustor and some NO_x is destroyed through the reverse of the reaction shown below.



By the second mechanism, free radicals present in the fuel rich portion of the flame reduce NO_x to nitrogen and water.

Based on NOXSO test programs on three different coal combustors (pulverized coal, tunnel furnace, and cyclone), boiler NO_x -destruction efficiencies have been measured from 57% to 75%. The highest NO_x -destruction efficiencies can be expected when the greatest portion of the recycle stream is used as primary air. For this analysis, a conservative value of 57% is used. It should be noted that net NO_x reductions greater than the boiler NO_x -destruction efficiency are easily achieved depending on the adsorber NO_x removal efficiency. For example, 85% net NO_x removal is achieved at an adsorber efficiency of 91% and a NO_x destruction efficiency of 57%. Figure 3 shows the relationship between adsorber NO_x removal efficiency, NO_x destruction in boiler, and net NO_x removal efficiency.

As discussed previously, attrited sorbent from the adsorber cyclone separator is transported to the sorbent heater by means of a dense-phase pneumatic lift. Attrited sorbent then exits the system in the NO_x recycle stream. Sorbent is returned to the power plant as part of the combustion air and is collected in either the bottom ash or in the electrostatic precipitators along with the fly ash. The mass of sorbent exiting the complete NOXSO system is only about 1% (by weight) of the combined bottom ash/fly ash generated by the power plant. All the chemical components found in NOXSO sorbent are also found in coal ash. Therefore, the mixture of ash and sorbent is chemically indistinguishable from ash itself. Both NOXSO sorbent and sorbent/ash mixtures have been subjected to toxic characteristic leaching procedure (TCLP) tests and been characterized as non-toxic based on the results of those tests. NOXSO treated flue gas will typically have a lower net particulate loading than untreated flue gas.

Once the sorbent has reached a temperature of 1150°F (621°C) in the sorbent heater, it is transported through two L-valves to the regenerator vessel. An L-valve is a non-mechanical valve that is used to transport solids and provide a gas seal between vessels. An example of an L-valve is shown in Figure 4. The L-valve consists of a downcomer, a horizontal section, and a riser. The downcomer is a length of pipe through which the sorbent flows

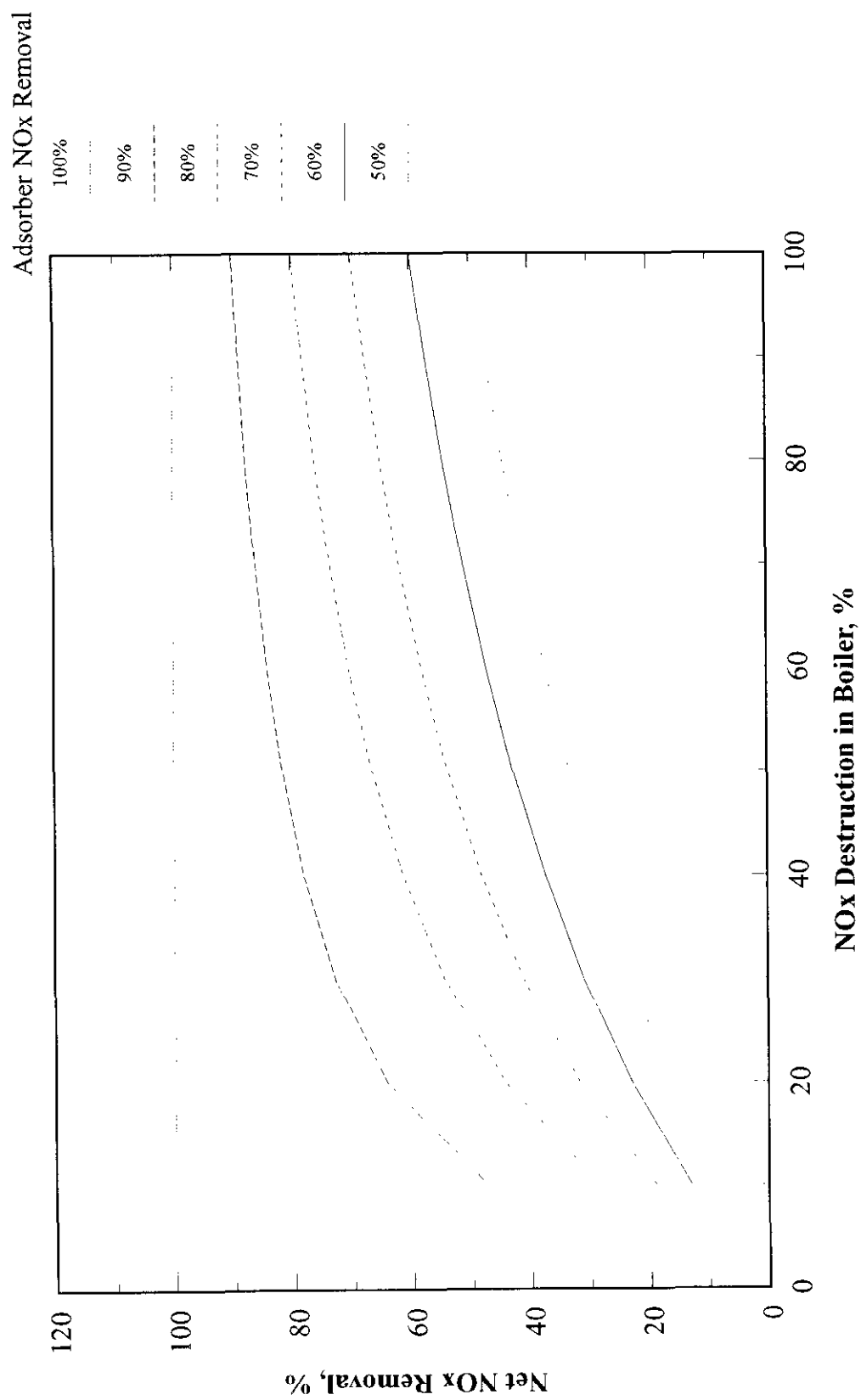


Figure 3. Net NO_x Removal Efficiencies

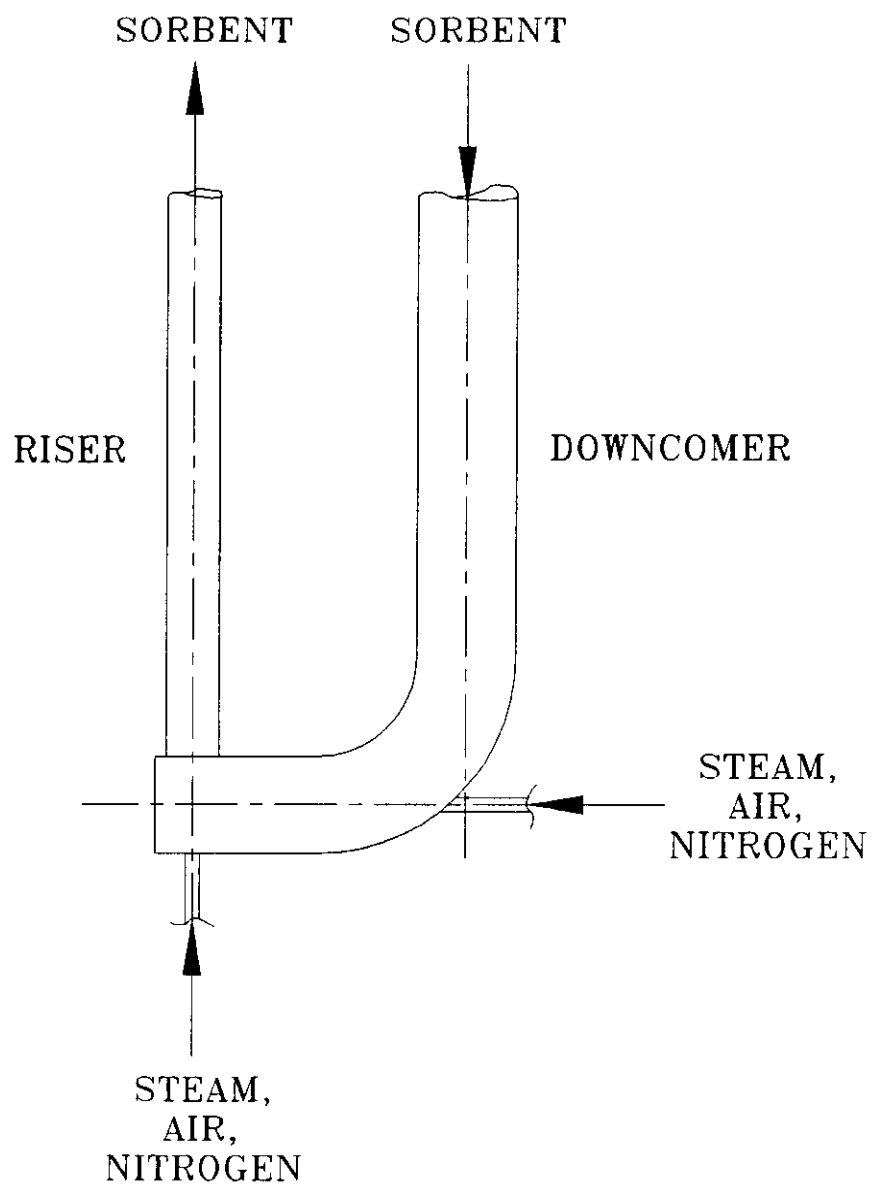


Figure 4. Schematic of NOXSO L-Valve

down as a moving bed and connects to a horizontal section of pipe. A gas source (N_2 for cold start-up and steam during normal operation) is used to convey the sorbent across the horizontal section of pipe and into the riser. A second gas source (also N_2 for cold start-up and steam during normal operation) is used to transport the sorbent up the riser and into a disengaging vessel. The horizontal section of the L-valve is made long enough so that when the gas source used to convey sorbent through the horizontal section is turned off, the sorbent's angle of repose is great enough to stop sorbent from flowing even when the riser conveying gas is still active. The moving bed of sorbent in the downcomer provides a seal to prevent oxygen in the sorbent heater from mixing with natural gas and H_2S in the regenerator.

The L-valve feeds sorbent to the disengaging vessel. The disengaging vessel is used to separate L-valve transport steam from the sorbent. The transport steam is piped to the flue gas duct downstream of the NOXSO adsorbers, and the sorbent gravity flows through a standpipe into the regenerator vessel. Separating the steam at this point prevents it from mixing with the regenerator off-gas and thus reduces the volume of gas sent to the sulfur recovery unit (SRU). In addition, because the sulfur formation reaction is an equilibrium controlled reaction with H_2O as a product, reducing the H_2O concentration of the feed gas increases the conversion achieved in the SRU.

Sorbent in the regenerator is contacted first with natural gas and then with steam in a countercurrent moving bed. Natural gas reacts with adsorbed sulfur compounds on the sorbent to form primarily SO_2 , H_2S , CO_2 , and H_2O as reaction products. Approximately 90-95% of the sulfur is removed from the sorbent in this step. The remaining 5-10% is removed from the sorbent through reaction with steam. The product of the steam reaction is H_2S .

The disengaging vessel and regenerator vessel both have carbon steel shells with internal refractory lining. The disengaging vessel has an inside diameter of 12 ft (3.7 m) while the regenerator vessel has an inside diameter of 23 ft (7.0 m). The two vessels are in a stacked configuration as shown in Figures 1 and 2.

The regenerator off-gas will be directed to the sulfur recovery unit where SO_2 and H_2S are converted to elemental sulfur. Sulfur, one of three potential by-products of the NOXSO process (sulfuric acid and liquid SO_2 being the others), is a commodity chemical with a current market value of \$30-40/ton. The Claus reaction requires H_2S and SO_2 in a molar ratio of 2 to 1. However, the NOXSO process generates a gas stream that contains H_2S and SO_2 in a molar ratio of 1 to 2. The first step of the sulfur plant is, therefore, to generate a hydrogen stream by oxidizing methane (natural gas) in substoichiometric ratios. Hydrogen is then catalytically reacted with SO_2 to generate the additional H_2S required to reach a 2 to 1 H_2S to SO_2 molar ratio. The remainder of the SRU contains two Claus convertors (where H_2S and SO_2 react to form sulfur), two sulfur condensers, two waste-heat recovery units, and two reheat units. Heat recovery in the SRU is done by generating steam. The sulfur recovery unit produces steam in excess of the NOXSO system requirements for sorbent regeneration and sorbent transport so no steam is required from the power plant. The excess 600 (4.1 MPa) psig steam produced by the SRU will be injected with power plant turbine extraction steam to one of the high-pressure feedwater heaters. This produces an energy credit, like the NO_x recycle stream, by reducing the demand for extraction steam and allowing more electricity to be produced. The elemental sulfur is stored in above ground tanks that have a two-week capacity. Sulfur will be removed from the site in a liquid form using tank trucks. Approximately two truckloads per day will be generated. The quantities of H_2S and SO_2 in the system at any instant in time are small and are well below the threshold limits imposed by OSHA regulation 29 CFR Part 1910. Sulfur and sorbent are the only two chemicals stored on site in appreciable quantities, and neither substance is affected by the OSHA regulations.

The final step in the NOXSO process is cooling of the sorbent. After regeneration, sorbent is transported by means of two L-valves from the regenerator to the sorbent cooler. These two L-valves also use N_2 for cold start-up and steam once the system is hot. The sorbent cooler is a four-stage fluidized-bed reactor that utilizes an ambient air stream to reduce the sorbent temperature to 275°F. The cooler, like the sorbent heater, has a tapered wall design to maintain a constant velocity on each stage. The average diameter of the sorbent cooler vessel is 26 ft (7.9 m). The top half of the sorbent cooler is made of chrome-moly

steel while the bottom half is made of carbon steel. Ambient air is provided by two 50% capacity blowers. A third 50% capacity blower is provided as a spare for the two operating units.

The air exiting the sorbent cooler is at a temperature of 850°F (454°C). This air stream then passes through a natural-gas-fired in-duct air heater that further raises the temperature to 1325°F (718°C). This air stream is then used to raise the sorbent temperature to 1150°F (621°C) in the sorbent heater. The sorbent cooler, air heater, and sorbent heater are in a stacked arrangement as shown in Figures 1 and 2.

Sorbent exiting the sorbent cooler vessel is transported to one of two surge tanks by means of two L-valves. Compressed air is the working fluid used in these two L-valves. The surge tanks are each 12 ft (3.7 m) in diameter. The purpose of the surge tanks is to act as a source and sink for sorbent so that a constant inventory can be maintained in all the other process vessels during periods of variable sorbent circulation rate.

Finally, sorbent is transported from the surge tanks back to the adsorber vessels completing one full cycle. One L-valve is used to transport sorbent from each surge tank to its respective adsorber. Again, compressed air is used as the working fluid.

In the NOXSO process, the sorbent experiences thousands of adsorption/regeneration cycles. The life of the sorbent is dictated by mechanical and thermal stresses experienced within the process. The fate of attrited sorbent was discussed previously. In this system, the attrition rate is estimated to be 112 lbs/hr (51 kg/hr) on a total system inventory of 360 tons of sorbent. Thus, through natural attrition processes, the system inventory is replaced on average every 10 months. The sorbent makeup is added in batches on a daily basis. A sorbent storage tank with two weeks sorbent makeup capacity is provided.

PROJECT SCHEDULE

The Cooperative Agreement was awarded in March of 1991. The project has been in a project definition phase while the pilot plant has been operating. Current emphasis is on incorporating pilot-plant results into a preliminary design for a commercial-scale plant and identifying a host site for the project. The project schedule by each phase is indicated in Table 1.

Project Definition	March 1991 - October 1994
Front End Engineering	November 1994 - June 1995
Design, Procure and Construct	July 1995 - November 1996
Operate	December 1996 - November 1998

Table 1. Project Schedule

ECONOMICS

The economic analysis is based on design, construction, and operation of a NOXSO plant to treat flue gas from a 500-MW power plant with operating criteria as given in Table 2. The 500-MW NOXSO plant consists of four 125-MW NOXSO plants with a single sulfur recovery unit. Details of this analysis are shown in Table 3. The NOXSO process will reduce SO₂ emissions by 98% to 0.09 lb/mmBtu (38.7 g/GJ) and reduce NO_x emissions by 85% to 0.12 lb/mmBtu (51.6 g/GJ). The total plant cost of the four module NOXSO plant is estimated at \$115.4 million or approximately \$231/kW. The total plant cost also includes the following: land (approximately 65,000 ft² (6,040 m²)), escalation during construction, initial catalyst charge, and all royalties and fees. Working capital was estimated at 3% of the total plant cost plus two months of the net operating costs. The start-up expense and organization was estimated at 2% of the total plant cost. The total capital investment of \$123.7 million, or about \$247/kW, is the value on which the fixed capital charge will be applied to recover the capital investment.

Plant Size, MW	500		
Coal Firing Rate, tph	198	Sulfur in Coal, %	2.8
Coal Heating Value, Btu/lb	12,000	Flue Gas Oxygen Conc., %	3.0
Net Heat Rate, Btu/kWh	9,500	Flue Gas SO ₂ Conc., ppm _d	2,500
Capacity Factor, %	90.0	Flue Gas NO _x Conc., ppm _d	600

Table 2. Design Criteria for Economic Analysis

Fixed and variable operating costs are also shown in Table 3. Due to the relative ease of operation, high reliability of the NOXSO process, and process automation through the use of a distributed computer process control system, it is anticipated that the power plant will not need to employ additional staff to operate the NOXSO system. As such, the operating labor shown is based on 1/2 of a skilled operator and 1/2 of an unskilled operator per shift with the appropriate overhead and supervisory charges applied. Maintenance materials and labor are estimated at \$1.2 million per year. Maintenance requirements are based on pilot plant operating experience and accepted industry equipment maintenance requirements. The general and administrative expense was estimated at 2% of the total plant cost. The total plant fixed-operating cost is \$3.8 million, or about 1 mill/kWh.

The gross variable operating costs, \$12.9 million year, or approximately 3.3 mills/kWh, were estimated at a 90% plant capacity factor and the unit rates shown. Including the revenue from the sale of elemental sulfur, \$1.7 million/year, the net operating and maintenance (O&M) cost of the NOXSO system designed for a 500-MW power plant burning 2.8% sulfur coal is \$15.0 million, or approximately 3.8 mills/kWh.

PLANT INFORMATION		
Power Plant Gross MW	500	
Capacity Factor	0.90	
Number of NOXSO Modules	4	
Heat Rate, Btu/kWh	9,500	
Coal Heating Value, Btu/lb	12,000	
Coal Sulfur, %	2.80	
NOx Loading, lb/mmBtu	0.80	
NOXSO PROCESS REMOVAL EFFICIENCIES		
SO ₂	98.0	
NO _x	85.0	
Combined	96.7	
EMISSIONS DATA, tpy		
Uncontrolled SO ₂	87,291	
Controlled SO ₂	1,747	
Phase 1 SO ₂ Limit (1)	46,811	
Uncontrolled NO _x	15,051	
Controlled NO _x	2,262	
CAPITAL COST, \$		
Total Plant Cost (2)	115,400,000	
Working Capital (3)	5,963,000	
Start-up Expense and Organization (4)	2,308,000	
Total Capital Investment	123,671,000	
\$/kW	247	
OPERATING AND MAINTENANCE COSTS		
Economic Parameters		
Electricity, \$/kWh	0.018	
Natural Gas, \$/mmBtu	2.50	
NOXSO Sorbent, \$/lb	1.50	
Water, \$/kgal	0.6	
Net Sulfur Value, \$/ton	40	
Fixed Charge Rate, % (5)	10.6	
NO _x Value, \$/ton (6)	800	
Fixed Operating Cost	(\$/year)	(mills/kWh)
Operating Labor (7)	306,000	0.08
Maintenance Materials & Labor (8)	1,191,000	0.30
G & A (4)	2,308,000	0.59
Total Fixed Operating Cost	3,805,000	0.97
Variable Operating Cost		
Water	112,000	0.03
Claus Catalyst	74,000	0.02
Natural Gas	6,273,000	1.59
Sorbent	5,296,000	1.34
Net Electricity	1,161,000	0.29
Total Variable Operating Cost	12,916,000	3.28
GROSS OPERATING AND MAINTENANCE COST	16,721,000	4.24
SULFUR	(1,714,000)	(0.43)
NET OPERATING AND MAINTENANCE COST	15,007,000	3.81
(1) 2.5 lb SO ₂ /mmBtu		
(2) Includes the following: initial catalyst charge, engineering and home office fees, royalties, escalation during construction, contingency, G&A, and constructor's fee.		
(3) 3% of Total Plant Cost + 2 months Net Operating Expenses.		
(4) 2% of Total Plant Cost.		
(5) Fixed Charge Rate based on 30-year book life, 20-year tax life, 38% composite Federal and State tax, and 2% for property taxes and insurance.		
(6) Conservative cost of NO _x removal based on SCR technology.		
(7) 1/2 skilled operator per shift, 1/2 unskilled operator per shift.		
(8) Estimate based on pilot-plant experience and expected life of equipment.		

Table 3. NOXSO Process Economic Analysis (1993 dollars)

CONSTANT DOLLAR LEVELIZED COST WITH SULFUR PLANT REVENUE	
\$/yr (9)	28,116,000
mills/kWh	7.1
\$/ton SO ₂ with NO _x Credit	209
\$/ton NO _x	800
CONSTANT DOLLAR LEVELIZED COST WITH SULFUR PLANT AND SO₂ EMISSION ALLOWANCE REVENUE	
Phase I Allowances	
Phase I Emission Limit	46,811
SO ₂ Emissions with NOXSO	1,747
Excess Allowances Generated @ \$300	\$13,519,000
Net Levelized Cost	
\$/yr (10)	14,597,000
mills/kWh	3.7
\$/ton SO ₂ with NO _x Credit	51
\$/ton NO _x	800
(9) Total Capital Investment x Fixed Charge Rate + O&M Costs - Sulfur Value.	
(10) Total Capital Investment x Fixed Charge Rate + O&M Costs - Sulfur Value - SO ₂ Allowance.	

Table 3. NOXSO Process Economic Analysis (1993 dollars) continued

A sensitivity analysis was performed to determine the effect of the net sale price of sulfur, the unit cost of natural gas and sorbent, and the energy credit on the net operating and maintenance cost. The results are shown in Figure 5. The baseline O&M is 3.8 mills/kWh and, as can be seen, large variations in the studied parameters do not significantly impact the net O&M cost. If sulfur is disposed at a zero net profit the operating cost will only increase to 4.24 mills/kWh. The price of natural gas can increase to \$3.50/mmBtu (\$3.32/GJ) producing a small increase in the net O&M cost from the baseline of 3.81 to 4.44 mills/kWh. The O&M cost will increase by 0.9 to 4.7 mills/kWh if the unit cost of the NOXSO sorbent increases by \$1.00 to \$2.50/lb. Assuming additional power cannot be generated by the power plant due to integration with the NOXSO process, the net O&M will increase from 3.81 to 4.14 mills/kWh. This assumes no credit was given for the resulting reduction in power-plant coal-feed rate.

On a constant 1993 dollar basis, i.e., no inflation applied to the variable operating costs, applying the fixed charge rate of 10.6% to the total capital investment and including the sulfur revenue, the levelized cost is \$28.2 million, or about 7.1 mills/kWh. The fixed charge rate is an EPRI generated value based on a 30-year book life, 20-year tax life, and a 38% composite federal and state tax rate [6]. It also includes 2% for insurance. Neglecting the value of NO_x removal, the levelized cost of the NOXSO system in terms of \$/ton SO₂ removed would be very competitive at \$329/ton removed. However, the NOXSO system is an integrated process which simultaneously removes SO₂ and NO_x and thus it is impossible to separate the cost of removing the SO₂ from the cost of removing NO_x. Assigning a value of \$800/ton of NO_x removed yields an SO₂ removal cost of \$209/ton which is superior to current FGD costs of \$350-600/ton [7]. The value of \$800/ton assigned to NO_x removal is based upon costs for high efficiency SCR processes. This is a conservative number, as SCR costs are typically higher. In addition, a range of cost effectiveness for NO_x control is cited at \$570-\$1,500/ton removed under several states Reasonably Available Control Technology (RACT) criteria.

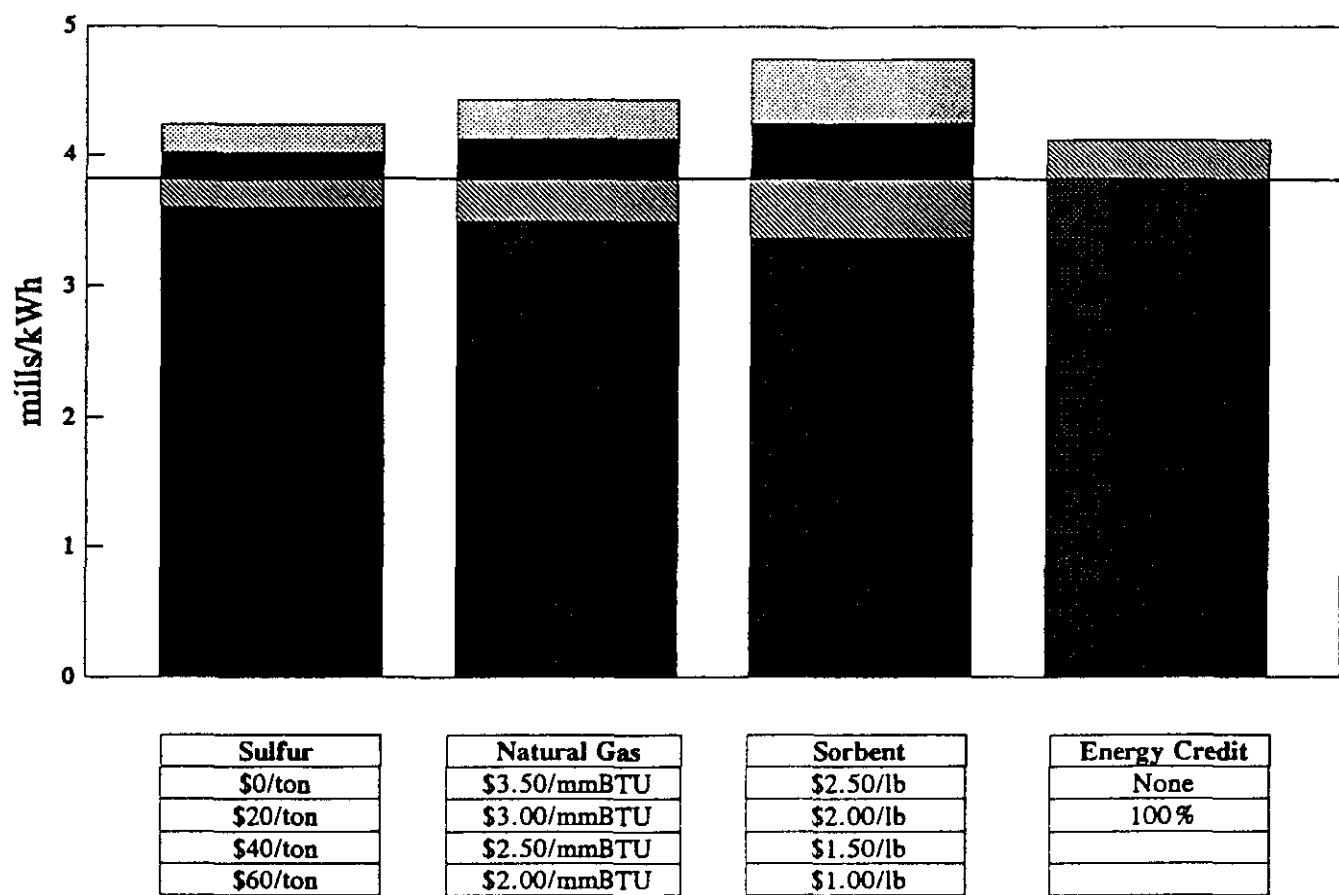


Figure 5. O&M Sensitivity Analysis

It is also appropriate to consider over-compliance since the high efficiency of the NOXSO process will allow a utility to generate SO₂ allowances which can be sold to partially offset the operating cost. The "Phase I SO₂ limit" in Table 3 is calculated based on allowable emissions of 2.5 lb SO₂/mmBtu (1.08 kg/GJ). Beginning with Phase II which starts in the year 2000, the number of allowances generated will decrease; however, it is also likely that the value of allowances will increase significantly, offsetting to some degree the reduction in allowances generated. Based on the above assumptions, \$13.5 million would be generated by the sale of SO₂ allowances offsetting the operating costs and reducing the levelized cost to \$14.5 million, or about 3.7 mills/kWh. The cost of SO₂ removal with the credit for NO_x removal decreases to \$51/ton.

Table 4 presents the utility and raw materials consumption for the four module NOXSO system based on the design criteria as given in Table 1.

ACKNOWLEDGEMENT

The authors wish to thank the following for their contributions to the project: U.S. Department of Energy's Pittsburgh Energy Technology Center, Morrison-Knudsen Corporation - MK-Ferguson Group, the Electric Power Research Institute, and the Gas Research Institute.

Natural Gas, lb/hr		
Air Heater	6,152	
Regenerator	3,644	
Sulfur Plant	<u>3,344</u>	
Total Natural Gas	13,140	
Sorbent Makeup Rate, lb/hr		
	448	
Steam, lb/hr		
Gross Claus Plant Steam	81,608	
Production		
NOXSO Process Steam	<u>(39,252)</u>	
Consumption		
Net Claus Plant Steam Production	42,356	
Water, gpm		
	387	
Electrical Power Consumption	<u>(kW)</u>	<u>Gross Power (%)</u>
Flue Gas Booster Fans	8,824	1.8
Sorbent Cooler/Heater Fans	2,748	0.5
Claus Plant	936	0.2
Air Compressors	3,104	0.6
Miscellaneous	<u>1,332</u>	<u>0.3</u>
Gross Electrical Power Consumption	16,944	3.4
Less Energy Credits		
FD Fan Credit	200	0.0
NOx Recycle Credit	4,032	0.8
Claus Steam Credit	3,446	0.7
Combustion Air Steam Preheat	<u>1,056</u>	<u>0.2</u>
Credit		
Total Energy Credits	<u>8,734</u>	<u>1.7</u>
Net Electrical Power Consumption	8,210	1.7

Table 4. Raw Material and Utility Consumption (500 MW NOXSO Plant)

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MILLIKEN STATION DEMONSTRATION PROJECT FGD RETROFIT UPDATE

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Introduction

The Milliken Clean Coal Demonstration Project is one of the nine Clean Coal Projects selected for funding in Round 4 of the U.S. DOE's Clean Coal Demonstration Program. The project's sponsor is New York State Electric and Gas Corporation (NYSEG). Project team members include CONSOL Inc., Saarberg-Holter-Umwelttechnik (SHU), NALCO/FuelTech, Stebbins Engineering and Manufacturing Co., DHR Technologies, and CE Air Preheater. Gilbert/Commonwealth is the Architect/Engineer and Construction Manager for the flue gas desulfurization (FGD) retrofit. The project will provide full-scale demonstration of a combination of innovative emission-reducing technologies and plant upgrades for the control of sulfur dioxide (SO_2) and nitrogen oxides (NO_x) emissions from a coal-fired steam generator without a significant loss of station efficiency.

The overall project goals are the following:

- 98% SO_2 removal efficiency using limestone while burning high sulfur coal;

- Up to 70% NO_x reduction using the NOXOUT selective non-catalytic reduction (SNCR) technology in conjunction with combustion modifications;

- Minimization of solid wastes by producing marketable by-products including commercial grade gypsum, calcium chloride, and fly ash;

- Zero wastewater discharge;

- Maintenance of station efficiency by using a high-efficiency heat-pipe air heater system and a low-power-consuming scrubber system.

The demonstration project is being conducted at NYSEG's Milliken Station, located in Lansing, New York. Milliken Station has two 150-MWe pulverized coal-fired units built in the 1950s by Combustion Engineering. The SHU FGD process and the combustion modifications are being installed on both units, but the NOXOUT process, Plant Economic Optimization Advisor (PEOA), and the high-efficiency air heater system will be installed on only one unit.

SO_2 Removal

The SHU process is the only developed wet-limestone FGD process designed specifically to employ the combined benefits of low-pH operation, formic acid

enhancement, single-loop cocurrent/countercurrent absorption, and in situ forced oxidation. In the SHU process, the flue gas is scrubbed with a limestone solution in a cocurrent/countercurrent absorber vessel that does not contain packing or gridwork. The absence of packing results in a low pressure drop across the absorber, which decreases energy consumption of the induced draft fans. The absence of packing also reduces the potential for plugging. The cocurrent/countercurrent design reduces the overall height of the absorber vessel compared to a conventional countercurrent design.

The SHU solution is maintained at a low pH by adding formic acid, which acts as a buffer, to the absorber. Formic acid addition enhances the process in several ways, including better SO₂ removal efficiency with limestone, lower limestone reagent consumption, lower blowdown rate, freedom from scaling and plugging, higher availability, lower maintenance, production of wallboard grade by-product, and improved energy efficiency compared to conventional FGD technologies.

With operation at lower pH, the limestone reagent dissolves more quickly. This means that less limestone is needed, the limestone doesn't have to be ground as finely, and there is less limestone contamination of the gypsum by-product. Operation at lower pH results in more efficient oxidation of the bisulfite reaction product to sulfate. Less excess air is needed for the oxidation reaction and the gypsum crystals created are larger and more easily dewatered. Formic acid buffering improves SO₂ removal efficiency. Slurry recirculation rates are reduced, saving both capital cost and energy. Buffering provides excellent stability and easy operation during load changes and transients. The process can tolerate higher chloride concentrations, reducing the amount of wastewater that must be processed. Finally, the potential for scaling of absorber internals is eliminated, resulting in reduced maintenance costs and improved availability.

The FGD process will be installed on both units 1 and 2 with common auxiliary equipment. A single split absorber will be used. This innovation features an absorber vessel divided into two sections to provide a separate absorber module for each unit. The design allows for more flexibility in power plant operations than does a single absorber while saving space on site (a key advantage for existing plants where space for retrofitting an FGD process is at a premium) and capital cost compared to two separate absorber vessels. The absorber shell is constructed of concrete, lined with ceramic tile. The tile lining has superior abrasion and corrosion resistance compared to rubber and alloy linings and is expected to last the life of the plant. In addition, the tile is easily installed at existing sites where space for construction is at a premium, making it ideal for use in retrofit applications.

Uniform gas flow and slurry spray distribution within the absorber are important for good gas/liquid contact and high SO₂ removal efficiency. Preliminary designs of static flow distribution devices were optimized through a series of wet and dry gas flow model tests conducted by Dyna Gen, Inc. The wet testing was especially valuable in uncovering and solving a potentially serious liquid maldistribution at the transition from cocurrent to countercurrent flow. Without wet testing, this problem would not have been discovered until start-up.

The absorbers use two-stage mist eliminators furnished by Munters. Whereas model DV 210 is used for the first stage in both absorber modules, the modules use two different second-stage designs. One absorber uses model DV-2130 and the other uses model T271. Model T271 is the vertical flow type tested by EPRI and commonly found in US installations. DV-2130 is the Munters-Euroform v-shaped module design commonly used in European installations. The project will

provide a side-by-side performance comparison of the two designs.

The design incorporates a new chimney erected on the roof of the FGD building, directly over the absorber vessel. Each absorber module will discharge directly into a dedicated fiberglass (FRP) flue. The two FRP flues, along with a common steel start-up bypass flue are enclosed within a 40-ft (12.2m) diameter steel chimney. This design saves space on site and eliminates the need for absorber outlet isolation dampers, which are typically high maintenance items.

Limestone Preparation and Addition

Limestone is delivered to the station by truck. Space is provided on site for a 180-day inventory. The stone is reclaimed by front-end loader and transferred by belt conveyor to two 24-hr surge bins in the FGD building. The limestone is ground and slurried in conventional closed-circuit, horizontal, ball mill, wet-grinding systems provided by Fuller. The limestone is transferred by weighfeeder from the surge bin to the mill. Clarified water (recycled process liquor) is also added to the mill. The mill discharges the slurry to the mill product tank, where it is diluted with more clarified water. The slurry is separated into product and reject fractions by hydrocyclone type classifiers. The 25% solids product is transferred by gravity to either of two 12-hour fresh slurry feed tanks. Redundant, continuous-loop piping systems are used to transfer the product slurry to the absorbers from the fresh slurry feed tanks. The reject fraction from the classifier is returned to the mill for additional grinding. Two grinding systems are provided, each with a capacity of 24 tph. One mill, operating 12 hours per day, can support the process. Each system is provided with two sets of classifiers. This allows the production of slurry with two different particle size distributions, 90% passing through 170 mesh and 90% passing through 325 mesh. The coarser grind is used during normal operation with formic acid. The finer grind allows the system to be operated without formic acid. The limestone preparation/addition system can be aligned as two independent trains, effectively segregating Unit 1 and Unit 2 process streams. This feature will enhance the flexibility of the installation for process evaluation purposes.

Gypsum Dewatering

A bleed stream of recycle slurry is processed for recovery of high quality by-product gypsum and calcium chloride brine. Water is recovered and recycled back to the process. There is zero wastewater discharge from the process. Unlike some competing processes that produce gypsum, the SHU by-product gypsum will be high grade and of consistent quality, regardless of the plant load level or flue gas SO₂ level. The gypsum will be dewatered to 6% surface moisture and delivered to customers in powder form. The absorber building has been designed for future addition of agglomeration equipment should market conditions require agglomerated product.

By-product gypsum solids are withdrawn from each absorber module by the bleed pumps and fed to primary hydrocyclones where they are concentrated to 25 wt%. The underflow from the primary hydrocyclones discharges to the centrifuge feed tanks. The overflow discharges to the secondary hydroclone feed tanks. Two primary hydrocyclone assemblies are provided. Each assembly can process the bleed from either or both absorber modules. The feed manifold of each hydrocyclone assembly has an internal partition which segregates the unit 1

and unit 2 bleed streams. This feature ensures that the feed rate to each individual hydrocyclone is constant whether or not the assembly is handling the bleed from one or both absorbers. In normal operation, the bleed from both absorbers is processed through one hydrocyclone assembly and the second assembly is a spare. If desired, both assemblies can operate in parallel.

The gypsum solids from the primary hydrocyclone underflow are concentrated to 94 wt% by Krauss-Maffei vertical basket centrifuges. Four centrifuges are provided, three operating and one standby. The centrifuges are fed from either of two centrifuge feed tanks through continuously circulating feed loops. The rubber-lined centrifuges are batch operated and incorporate a washing step to achieve a residual chloride concentration of less than 100 ppm. The system is configured to allow segregation of the unit 1 and unit 2 liquid streams. The centrate is returned to the absorbers through the filtrate tanks. The gypsum solids are transferred by belt conveyor to an on-site storage building. Gypsum in the 5000-ton capacity storage building will be reclaimed by front-end loader and trucked from the site.

A portion of the overflow from the primary hydrocyclones is processed by the secondary hydroclones for use as clarified water for limestone preparation, system flushing, and blowdown to the FGD wastewater treatment system. Gypsum solids in the underflow from the secondary hydrocyclones and the balance of the primary hydrocyclone overflow are returned to the absorbers via the filtrate tanks. Two secondary hydrocyclone assemblies are provided, one dedicated to each primary hydrocyclone assembly, maintaining the capability of segregating the unit 1 and unit 2 process streams.

FGD Blowdown Treatment

The FGD Blowdown Treatment System consists of two subsystems, the pretreatment system furnished by Infilco Degremont Inc.(IDI) and the brine concentration system, furnished by Resources Conservation Co.(RCC). The project will be the first demonstration of the production and marketing of FGD by-product calcium chloride.

The pretreatment system removes suspended and dissolved solids from the blowdown stream prior to the brine concentration process. The pretreatment process consists of the following steps:

1. An agitated equalization tank to balance the FGD wastewater composition and flow.
2. pH elevation, calcium sulfate desaturation and magnesium hydroxide precipitation using lime. By elevating the pH to 11.0-11.2, most heavy metals will be removed. In particular, the high pH will lead to precipitation of magnesium hydroxide, leading to a purer calcium chloride salt product. The use of lime also enhances the removal of fluoride ion as calcium fluoride. Sludge is recirculated from the downstream clarifier to aid the desaturation process.
3. Secondary precipitation of heavy metals as more insoluble organosulfides using the organosulfide TMT.
4. Coagulation with ferric chloride.
5. Dosing of flocculation aid (polymer) to the reactor of the DensaDeg unit. Metal hydroxide sludges are voluminous and tend to create much lighter flocs than gypsum sludge. Sedimentation is improved by adding polymer as a flocculation aid.

6. Flocculation/sludge densification, thickening, and final clarification in the DensaDeg unit. The DensaDeg is a three-stage unit comprising a solids-contact reaction zone, a presettler-thickener, and lamellar settling tubes in the upper part of the thickener. The water entering the clarification zone has a very low solids content and the lamellar tubes serve only to catch fugative particles carried over. Water leaving this zone has less than 20 ppm solids.

7. Excess sludge withdrawal conditioning with lime, and dewatering with a plate and frame filter press. The addition of lime in the sludge holding tank aids the dewaterability of the sludge, allowing a drier cake to be formed, and also helps stabilize the metal hydroxides.

The brine concentration system processes the effluent from the pretreatment system through a vapor-compression type falling-film evaporator, producing a very pure distillate that is recycled to the FGD system as process makeup water. The system's by-product salt will be calcium chloride meeting NYSDOT requirements for use in dust control, soil stabilization, ice control, and other highway construction related purposes. This material will be Type B (liquid calcium chloride solution) with at least 33% CaCl_2 , meeting ASTM D98.

The pretreated FGD blowdown is conditioned with sulfuric acid and an inhibitor for scale prevention. It is then preheated, deaerated, heated to near boiling, and fed to the evaporator sump where it mixes with recirculating, concentrated brine slurry. The slurry is pumped to the brine concentrator (BC) condensor floodbox where it is distributed as a thin film on the inside walls of titanium tubes. As the slurry film flows down the tubes, the water is evaporated. The resulting steam is drawn through mist eliminator pads to the vapor compressor, which raises its saturation temperature to above the boiling temperature of the recirculating brine. The compressed steam is then introduced to the condenser where it gives up its heat of vaporization (to heat the thin film in the inside of the tubes) and condenses on the outside of the tube walls. This condensate is collected in the distillate tank, cooled by heat exchange with the feed stream, and returned to the FGD system. As the falling film evaporates, calcium sulfate begins to crystalize. The calcium sulfate seed crystals provide nucleation sites to prevent scaling of the tubes. Control of the concentration of both suspended and dissolved solids in the evaporator sump is critical to prevent the precipitation of secondary salts and the resultant scaling of the evaporator tubes. A side stream of recirculating brine is processed by a hydrocyclone. The underflow is returned to the BC sump. The overflow is either recirculated to the brine concentrator or diverted to the product tank, based upon its dissolved solids concentration. A second side stream of recirculating brine is diverted to the product tank to control the concentration of suspended solids. The 33% brine product is then cooled and transported to market by truck.

Plant Economic Optimization Advisor

The Plant Economic Optimization Advisor (PEOA) is an on-line performance support system developed by DHR Technologies, Inc. to assist plant personnel in meeting the requirements of Title IV of the 1990 Clean Air Act Amendments and in optimizing overall plant economic performance. The PEOA system will be installed on one of the units. The system will integrate key aspects of plant information management and analysis to assist plant personnel with optimization of overall plant economic performance, including steam generator and turbine equipment, emissions systems, heat transfer systems, auxiliary systems, and waste management systems. The system will be designed primarily for plant operators but will also provide powerful, cost-saving features for

engineers and managers. The PEOA will automatically determine and display key operational and control setpoints for optimized cost operation. The system will provide operators with on-line emissions monitoring and diagnostic capabilities, along with rapid access to reports and trend information. The PEOA optimization algorithms will evaluate key data emissions parameters, such as NO_x, SO₂, O₂, CO, CO₂, CaCl, Carbon in Ash, and Opacity, plus other operational parameters such as boiler and turbine mixing. The system will provide "what-if" capabilities to allow users to utilize the optimization features to evaluate various operating scenarios. In addition to providing optimized setpoint data, the PEOA system will also provide plant operators and engineers with expert advice and information to help optimize total plant performance.

Construction

Engineering and design work for the project began in January 1992. Construction started in April 1993, and is on target to begin scrubbing the first unit in December 1994. As with most FGD retrofit projects, running a major construction project on a site shared with an operating unit posed several construction coordination challenges. One of the major drivers behind the construction plan, in addition to DOE's commitment to be ready to begin the demonstration program in June 1995, was the desire to use existing unit scheduled outages for tying in the FGD systems. This strategy avoids the project's causing the station to lose generating time and the associated revenue. Unit 2 was scheduled for a maintenance outage in late 1994 and Unit 1 in spring 1995. Since only a partial bypass is being provided around the scrubbers, once a unit is tied in, the FGD system must be operational.

Meeting the unit 2 outage schedule meant installing mechanical equipment as well as piping, the absorber vessel, and the roof-mounted chimney during the upstate Finger Lake region winter. It was therefore essential that the FGD building be erected and enclosed by January 1994. Stebbins' unique construction method, which uses the Stebbins tile liner as the formwork for the concrete pours, limits the height of each pour to about one ft. Accordingly, 33 weeks were scheduled for erection of the 108-ft (33m) tall absorber vessel. This meant that the building steel had to be erected in parallel with the absorber. To accommodate the associated safety issues, the initial vessel erection was done on the second shift. The building was enclosed in time to allow mechanical work to proceed without major disruption from the unusually severe winter weather.

International Chimney mobilized on site in December, 1993, and began erecting the stack in January. The 140-ft (42.6m)-tall, 40-ft (12.2m)-diameter steel shell was fabricated on site in 10-ft (3m) sections, lifted into position by the 350 ton DeMag, using a 420-ft (128m) boom, and welded in place. The 12-ft (3.6m) diameter, 227-ft (69.2m) tall FRP flues were shop fabricated in 40-ft (12.2m) spools, lifted into the shell with the crane and attached with bell/spigot FRP butt welds. The stack was topped out in May, in time to make way for erection of the limestone and gypsum conveyors.

System check out and start-up activities will be taking place through the summer and fall with the first unit coming on line in December. We look forward to having several months of operating data to present at next year's Coal Conference.

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1. D.T. O'Dea, et. al., Overview of the Milliken Station Clean Coal Demonstration Project, Ninth Annual International Pittsburgh Coal

Conference, Pittsburgh, Pa., September, 1992.

2. H.K.Petzel, Development and operating experiences of the S-H-U FGD process at the Volklingen power station, 1991 SO₂ Control Symposium, Washington, D.C., December, 1991.

TECHNICAL SESSION 11:
ADVANCED ELECTRIC POWER
GENERATION SYSTEMS
(HEAT ENGINES)

Co-Chairs:

Nelson F. Rekos
Morgantown Energy Technology Center
U.S. Department of Energy

George E. Lynch
Office of Clean Coal Technology
U.S. Department of Energy

Coal-Fueled Diesels for Modular Power Generation

R. P. Wilson, Jr., Arthur D. Little, Inc.

Abstract

Easton Utilities Commission, Copper Energy Services, and Arthur D. Little will demonstrate the Clean Coal Diesel as part of the Department of Energy Clean Coal V program. In this project, a 14 MW plant will be built in Easton, Maryland, to demonstrate the commercial viability of the technology. In addition to DOE funding, this project which utilizes Ohio coal will also be funded by the Ohio Coal Development Office as well as several of the industrial participants.

The technology will be demonstrated with a 10-100 MW power plant aimed at the non utility generation market. As such, the Clean Coal Diesel fills a gap in the Clean Coal Program since below 100 MW there is no competitive coal-to-busbar power plant technology.

The performance characteristics of the mature commercial embodiment of the Clean Coal Diesel are truly impressive.

- 48% efficiency LHV (7001 Btu/kWh heat rate)
- \$1300/kW installed cost
- Emission levels controlled to 50-70% below current New Source Performance Standards

In this paper, the overall goals of the project will be discussed in detail, along with the methods to achieve the goals. The results of testing with a single and a six cylinder engine under a separate DOE contract will be given. Finally, the Clean Coal project schedule and test plan will be presented.

**WARREN STATION
CLEAN COAL TECHNOLOGY PROJECT
DOE CLEAN COAL FIVE PROJECT**

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WARREN STATION CLEAN COAL TECHNOLOGY PROJECT

INTRODUCTION

The early rounds of the CCT program initiated in 1986 focused on the immediate environmental challenges facing coal users. An example is the Penelec Project selected in Round 3 where Confined Zone Dispersion is utilized to reduce SO₂ at Seward Station. Lime slurry is injected in half the gas outlet of No. 15 boiler in order to remove half of the SO₂ in the gas stream.

The selections being made in Round 5 recognize that coal can continue to play a pivotal role in meeting the demand for economical electricity in the United States, as well as abroad.

Round 5 is the final scheduled round of the program (Exhibit I). A total of 24 projects was submitted to DOE for consideration; 5 were selected to receive funding. On May 4, 1993, the Warren Unit No. 2 Repowering project utilizing Externally Fired Combined Cycle (EFCC) Technology was selected. The technology utilizes coal to heat compressed air to drive the combined cycle gas turbine which drives the compressor supplying the air and a generator providing electricity through the use of a high temperature ceramic tubed heat exchanger.

One of the criteria for selection as a demonstration site is the amount of equity the industry-sponsor is willing to invest in the project. In the case of the Warren project, the Project Team (Pennsylvania Electric Company, Hague International, and Black & Veatch) sought a full 50% DOE participation, or \$73.4 MM (\$146.8 MM Total Project Cost).

PROJECT GOALS

The goals of the Project briefly stated are to demonstrate the following advantages of the EFCC Technology (Exhibit II):

- Demonstrate the reliability of the EFCC Technology (design and materials) on a commercially sized unit.

- Improvement of Heat Rate of Repowered Unit.
- Increased Station Capacity
- Reduce NO_x generated to less than environmental requirements (NSPS).
- Reduce CO₂ generation per MW generated.
- Demonstrate economic competitiveness of the Repowered Unit while achieving or bettering all environmental regulatory requirements.

PROJECT ORGANIZATION AND RESPONSIBILITIES

Pennsylvania Electric Company (Penelec) located in Johnstown, Pennsylvania, has been working with Hague International (HI or Hague) located in South Portland, Maine, developer of the EFCC Technology, and Black & Veatch (B&V) located in Kansas City, Missouri, in the development of a repowering scheme for Penelec's Warren Station Unit No. 2. The repowering will replace two (2) of the Station's existing steam generators (boilers) with an Externally-Fired Combined Cycle (EFCC) utilizing a new combustion turbine (CT) and incorporating the unit's *existing steam turbine generator*.

Hague International is a high technology, engineering and manufacturing corporation specializing in thermal energy conversion equipment and micro-processor based electronic controls for high temperature industrial processes. (Exhibit III) From its inception, Hague has specialized in the design and development of systems and products which can be used to improve the thermal efficiency of high temperature energy conversion processes. Hague is best known for its work in high temperature ceramic heat exchangers and has obtained a prominent position nationally and internationally in this area. The ceramic heat exchanger can accept inlet process gas temperatures up to 2,800 degrees F. This capability makes significant improvements in a number of industrial high temperature processes.

Hague will be responsible for the design, procurement, and fabrication of the equipment for the Power Island portion of the Project. (Exhibit IV) The Power Island consists of the Combustor, Slag Screen, Ceramic Heat Exchanger, Gas Turbine, Heat Recovery Boiler, Interconnecting Ductwork and associated auxiliaries. Hague is also responsible for development and operation

of the Kennebunk, Maine Test Facility, where a pilot scale of the EFCC Cycle is being developed and tested. The tests to be run at the Kennebunk Test Facility are critical to the Warren EFCC Repowering Project. Hague International is also responsible for ongoing testing of ceramic materials for use in the cycle.

Black and Veatch is a major AE and Construction Management firm well established in the United States and internationally. (Exhibit V) B&V is providing the AE, Project and Construction Management Services for the Warren EFCC Repowering Project. Hague will be providing the Power Island portion of the project acting in the role of a sub-contractor to B&V. B&V will also procure all of the Balance of Plant (BOP) systems (scrubber, baghouse, structural facilities, water treating systems, coal handling system upgrades, ash handling systems, electrical/transmissions systems, etc.) and all other services and materials necessary for the construction of the repowered facility including environmental licensing support. (Exhibit VI)

Penelec is a major electric utility which owns and/or operates 5200 MW's of fossil-fired electric generating facilities in Pennsylvania. (Exhibit VII) Penelec/GPU is the owner and operator of the Warren Station. Penelec/GPU is the Participant for the Cooperative Agreement with the DOE and is responsible for providing the majority of the non-DOE 50% funds. Penelec/GPU has the overall responsibility for Management and Administration of the Project and will operate the repowered unit.

SITE DESCRIPTION

Warren Station is located in northwestern Pennsylvania 2 miles west of the city of Warren on the Allegheny River. (Exhibit VIII) The Warren Station Units 1 and 2 went into service in 1948 and 1949, respectively. The Station has four Erie City pulverized coal fired boilers which produce 225,000 lb/hour steam at 875 PSIG and 885 F each and two Westinghouse steam turbine-generators (new HP shells in 1970 and LP shells in 1990) each rated at 44 MW. The units share a common stack, coal handling system, circulating water supply and return, etc., which will continue to be shared by the Repowered EFCC Unit. The station and its equipment have been well maintained. However, due to its higher heat rate and anticipated increased costs

associated with compliance with the 1990 Clean Air Act Regulations, steps were necessary to assure the station would be competitive. The EFCC Repowering of Unit 2 will result in the unit continuing to be in compliance with environmental regulations while providing competitively priced power.

Factors which lead to the selection of the Warren Station as the Demonstration Site include unit size, available space to conveniently install the EFCC Unit, good conditions of the existing equipment and systems, turbine inlet conditions, and availability and condition of shared systems.

TECHNOLOGY AND PROJECT DESCRIPTION

The Warren EFCC Repowered Unit 2 will burn approximately 26 tons of pulverized bituminous coal per hour in an atmospheric combustor to produce hot gases. (Exhibit IX) The combustor, approximately 85 feet in height and 25 feet in diameter, is designed to burn coal in three distinct stages to reduce nitrogen oxide (NO_x) emissions to well below the New Source Performance Standard (NSPS) limit, estimated NO_x emissions from the Repowered Unit will be 0.13 lb/MM Btu. Currently NO_x is 0.65 lb/MM Btu. The hot flue gases from the combustor flow through a slag screen, made up of rows of ceramic rods on which the molten ash particles in the gas adhere. Thermal cycling of the rods by means of electric heating assists in removal of the ash to the hopper below. The system removes ash particles greater than 12 microns in size. The gases then move into a four pass ceramic heat exchanger constructed with proprietary designed alumina/silicon carbide ceramic tubes approximately 4 inches in diameter capable of operating at the high flue gas temperatures coming from the combustor. Each pass is 16 ft. in height (one tube section) with the tube section connectors acting as dividers between the four passes. There are approximately 700 tube-strings and the ceramic heat exchanger will be approximately 88 feet in height, 27 feet wide and 8 feet deep.

The hot flue gases transfer their heat energy through a single pass of the ceramic tubes to the compressed air provided by the Gas Turbine Compressor which, in turn, drives the combustion turbine, generating 22 MW (gross). The turbine inlet air temperature for the unit will be 1800F.

A key factor of the EFCC Process is that the process protects the combustion turbine by using clean air to drive the Gas Turbine eliminating the small ash particles and other products of combustion from being carried by the hot combustion gases into the turbine. This saves expensive wear and tear typical of other fossil-fueled turbines. The exhausted hot air from the combustion turbine is used as pre-heated combustion air in the combustor, increasing the cycle efficiency.

The hot flue gas exiting the ceramic heat exchanger passes through the heat-recovery boiler (which replaces two of the existing station boilers) to produce steam to drive the existing Unit 2 steam turbine at the Warren Station, producing 48.0 MW (gross). The total net EFCC Unit 2 output will be 66.0 MW (allowing 4.0 MW for auxiliary uses). The gas exiting the Heat Recovery Boiler is then cleaned by a dry spray scrubber and baghouse system to reduce SO₂ levels by 80% and Particulate to below 0.03 lb/MBTU. The combination of the dry spray scrubber and baghouse is also recognized as one of the most effective ways of reducing trace heavy metals (toxics) from the gas stream. A new Distributed Control and Information (DCI) System will be installed for the EFCC unit and will be integrated with the existing Warren Station controls.

The Repowered Unit No. 2 will take advantage of the existing Unit No. 2 steam turbine generator, condenser, circulating water system, major portions of the coal handling system, electrical systems, stack, etc. The Warren Unit No. 2 is well suited for the Project due to its size, available space, conditions of the facility and equipment, steam turbine inlet conditions and available shared systems.

The Repowered Warren Unit No. 2 is projected to have a significantly improved heat rate of approximately 9,600 BTU/KWH, corresponding increases in capacity factors and good availability. (Exhibit X) The remaining half of the station which is not repowered will continue to produce 44 MW net, for a total net plant output of 110.0 MW; a 50 percent increase in Unit No. 2 and 25 percent increase in Warren Station's total net rating will result from the EFCC Repowering of Unit 2.

SCHEDULE

The Warren Repowering Project, due to its built-in constraints of time, cost and environmental issues, makes scheduling this project a challenge in itself. (Exhibit XI) The Project needs to go from concept to startup in two and a half years with not-to-exceed costs and a changing regulatory environment. Penelec and Black & Veatch have decided to use a fully integrated project cost/schedule control system which is capable of providing necessary Project Management information and reports to meet DOE and Penelec requirements. B&V is providing their monitoring and control systems and reporting as part of their Project Management effort. We will have a schedule consisting of approximately 3000 activities with craft and cost resources assigned at the activity level. The Cost Schedule System will be used to provide management with Project cash flows, areas of concern and performance evaluation. The Project has been broken down into three Phases and four Budget Periods which cover all activities from conceptual design through the 32.5 Month Demonstration Period. The overall schedule depends upon on-going activities at the Hague Kennebunk Test Facility, the DOE NEPA Process, Licensing and Permitting activities, as well as design, procurement and construction activities.

BENEFITS

The benefits of a successful demonstration include: (Exhibit XII)

- Assures that the Warren Station meets all environmental standards including those dictated by the Clean Air Act Amendments. In particular the Power Island will result in reduction of NO_x emissions to 0.13 lb/MBTU, well below the proposed standards, and a 30% reduction in CO₂ produced per MW generated, reducing greenhouse gases. The addition of a dry spray scrubber and baghouse on the Repowered Unit assures compliance with SO₂ and Particulate requirements and decreased toxics in the stack gases.
- Provides for extended life of the Warren Station, providing economic benefits to the region and to Penelec/GPU.
- Increase Unit capacity from 44 MW to 66 MW, a 50% increase.

- During construction, the Project will employ approximately 300 to 350 construction personnel.
- It will allow the Warren Station to continue to burn local coal from the Pennsylvania market, about 225,000 tons will be burned annually for the Repowered Unit 2 alone. In addition, a successful demonstration could open new markets for coals in Pennsylvania and across the USA.
- The station's heat rate can be improved to $\approx 9,600$ (HHV) Btu/Kwh, a 30.0 percent improvement over the existing unit heat rate.
- The EFCC Cycle utilizes equipment and systems which are familiar to electric generating stations, with the exception of the ceramic components, and do not require any new "chemical plant" operations.
- A successful demonstration will also enable Warren Station to produce power at costs which will be competitive with the larger central generating stations.

This project demonstrates a technology which will provide available options for repowering of existing coal-fired stations as well as new coal-fired units, which will be environmentally attractive and economically competitive. (Exhibit XIII) The ramifications of this technology extend throughout the utility industry. Nationwide there are more than 500 coal-fired steam plants over the age of 30 years. More than 200 of those units are in the 30-100 MWe range. Many of these 500 units may become candidates for repowering using this technology through the year 2010.

Round 5 Project Description

- Round 5 Project
- Government Funding - \$73.4 MM
- Partners
 - Hague International
 - Black & Veatch
 - Penelec / GPU

GPU / GENCO Exhibit I

Project Goals

- Heat Rate Improvement
- Demonstrate EFCC Reliability
- Increase Station Capacity
- Compliance With All Regulatory Requirements
- Demonstrate Economic Competitiveness

GPU / GENCO Exhibit II

Technology

- Hague International
 - High Temperature Ceramic Heat Exchangers
 - Externally Fired Combined Cycle
 - Power Island

GPU / GENCO Exhibit III

Power Island

- Combustor
- Slag Screen
- Ceramic Heat Exchanger
- Gas Turbine
- Heat Recovery Boiler
- Ductwork and auxiliaries

GPU / GENCO Exhibit IV

Balance of Plant

- Project Management
- A&E Services
- Balance of Plant
- Construction Management

GPU / GENCO Exhibit V

Balance of Plant

- Scrubber
- Baghouse
- Structural
- Water Treating
- Electrical/Transmission
- Modifications to Existing Equipment
- Environmental Licensing Support

GPU / GENCO Exhibit VI

Warren Repowering

- Owns and/or Operates 5200 MW's Fossil Fired
- Owners of Warren Station
- Participate in Cooperative Agreement with DOE
- Funding Majority of non-DOE 50% Share
- Overall Administrative and Management Responsibilities
- Operate the Repowered Unit

GPU / GENCO Exhibit VII

Current Operation Statistics

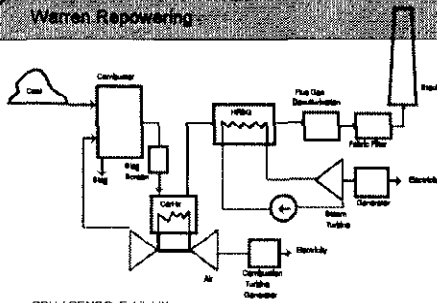
Warren Repowering

	Unit 2
Rating (MWH Net)	44
Equiv. Avail.	90
Capacity Factor	51

GPU / GENCO Exhibit VIII

EFCC Process

Warren Repowering



GPU / GENCO Exhibit IX

Repowered Statistics

Warren Repowering

	Unit 2
Rating (MWH Net)	66
Capacity Factor	85
Heat Rate (HHV)	9600

GPU / GENCO Exhibit X

Scheduling

Warren Repowering

- Concept to Start-Up 30 Months
- Not-to-Exceed Costs
- Changing Environment
- Integrated Project Cost/Schedule System
- 3000 Activities

GPU / GENCO Exhibit X1

Benefits

Warren Repowering

- Meet or Exceed CAAA Standards
- Extended life / Economic
- Increase Unit 2 Capacity 44 MW to 66 MW (Net)
- Employ 300 - 350 Construction Personnel
- Local Coal - 225,000 tons annually
- Efficiency Improvements
 - 9600 Btu/kWh (HHV)
- Competitive Costs

GPU / GENCO Exhibit XIII

US Coal-Fired Units

- Over 30 Years Old
- 500 units nationwide
- 200 units in 30-100 MW range
- Candidate for the EFCC Technology

GPU / GENCO Exhibit XIII

TECHNICAL SESSION 12:

**ADVANCED ELECTRIC POWER
GENERATION SYSTEMS (FBC)**

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I. INTRODUCTION

The York County Energy Partners, L.P. cogeneration project is a 250 MW (gross) facility which will employ a single circulating fluidized bed boiler and steam extraction turbine. The facility will be constructed in North Codorus Township, Pennsylvania (approximately 8 miles southwest of York, Pennsylvania) and will supply up to 400,000 pounds per hour of 600 psig steam to the adjacent P. H. Glatfelter Company paper mill. The facility will also supply 227 MWe of electricity under a long-term contract to Metropolitan Edison Company, the local investor-owned electric utility. Construction is scheduled to begin in early 1995 with commercial operation beginning in late 1997. The project is the recipient of a Round I award under the U.S. Department of Energy's Clean Coal Technology program.

York County Energy Partners, L.P. (YCEP) is a wholly-owned project company of Air Products and Chemicals, Inc. of Allentown, Pennsylvania. Air Products is a leading developer, owner, operator of environmental and energy systems and currently operates three cogeneration facilities, two of which use circulating fluidized bed (CFB) technology.

Project highlights include:

- Scale-up and operation of the world's largest circulating fluidized bed boiler.
- The facility will be the first coal-fired independent power plant in Pennsylvania to offer turndown to 50% of its rated output for economic dispatch.
- Ash by-product will have a beneficial reuse by reclaiming surface mining areas in eastern Pennsylvania.
- Displacement of an old P. H. Glatfelter boiler resulting in a net improvement in air quality (SO_x, NO_x and PM₁₀).
- Reuse of the papermill's treated wastewater as the cooling water, thereby reusing a critical water resource rather than consuming the area's fresh water supplies.

The total capital cost of this facility is expected to be nearly \$400 million, with \$75 million of financial assistance to be provided through the Department of Energy's Clean Coal Technology program.

II. PROJECT HISTORY

Original Project Sponsor

In June 1989, the City of Tallahassee, Florida, was selected from the alternate candidate's list to participate in Round I of the Department of Energy's (DOE) Clean Coal Technology program. Tallahassee had proposed to repower one of its Arvah B. Hopkins Generating Station units with a single circulating fluidized bed (CFB) boiler. The purpose of this repowering was to help Tallahassee diversify away from its complete reliance on natural gas for electricity production. Tallahassee executed a Cooperative Agreement with DOE in November 1990 which would provide approximately \$75 million toward this repowering. Subsequently in June 1991, Tallahassee executed a boiler supply agreement with Foster Wheeler Energy Corporation (Clinton, New Jersey) for the single CFB to be used for the project.

During development of the project, the repowering came under criticism for both economic and environmental reasons. Between 1986 and 1991, the drop in natural gas prices made the repowering less economically attractive, and local grassroots opposition brought up environmental concerns focused on the use of coal. As a result, Tallahassee decided in September 1991 to discontinue the repowering project and expressed its willingness to transfer the project to another party.

Transfer to Air Products and Chemicals, Inc.

Since early 1991, Air Products had been developing a coal-fired project to provide for a documented electricity need in Pennsylvania. While Tallahassee was winding down its project, Air Products expressed an interest in the technology and the Clean Coal funding for its York County Energy Partners (YCEP) project. In June 1992, YCEP executed the necessary agreements with DOE and the project was officially moved to York County, Pennsylvania.

The Need for Power in Pennsylvania

In the early 1990's, Metropolitan Edison Company (Met-Ed) documented its need for additional capacity in its system. Met-Ed is the fastest growing electric utility in Pennsylvania and by the end of the decade will need to acquire an additional 500 MW of generating capacity. YCEP worked with Met-Ed and the Pennsylvania Public Utility Commission in late 1991 and 1992 to allow the YCEP project to provide for 227 MW of Met-Ed's stated electricity need, concluding in the execution in June 1992 of a 25-year power supply agreement. Significant in the contract is the ability for Met-Ed to dispatch the YCEP facility between 114 MW and 227 MW (i.e., 50% to 100%) to allow Met-Ed to vary output on an hour-by-hour basis to economically provide power to its customers.

P. H. Glatfelter As Steam Host

When originally proposed in 1991, the YCEP project was to be located adjacent to a dolomite refractory manufacturing facility in West Manchester Township, Pennsylvania. However, due to environmental advantages inherent at a site adjacent to P. H. Glatfelter Company's Spring Grove paper mill, YCEP relocated the project in February 1993 to North Codorus Township, approximately six miles southwest of the West Manchester site. At this site, YCEP will supply up to 400,000 pounds per hour of 600 psig steam to the Glatfelter paper mill which in turn will allow the mill to curtail operations of its 1950's-vintage No. 4 coal-fired boiler. This boiler curtailment will result in a net reduction (i.e., including emissions from the YCEP facility) of over three million pounds per year of sulfur dioxide emissions, as well as a reduction of both oxides of nitrogen and particulates.

P. H. Glatfelter Company

P. H. Glatfelter Company (PHG) is a manufacturer of printing, writing and specialty papers. PHG operates three paper mills located in Spring Grove, Pennsylvania, Pisgah Forest, North Carolina and Neenah, Wisconsin, respectively. The company is headquartered in Spring Grove which is also the location of its largest mill and near the site of the proposed YCEP facility.

The Spring Grove mill manufactures printing and writing papers. The mill employs 1200, 800 of whom are represented by the United Paperworkers International Union. The

facility is electrically self-sufficient, capable of producing over 1.1 million pounds of steam per hour from three coal-fired boilers and two chemical recovery boilers (to be replaced by a single recovery boiler by mid-1994). One of PHG's coal-fired boilers is a CFB which began operating in 1989. Steam provided by the YCEP facility will obviate the need to continuously operate an existing pulverized coal boiler (called the No. 4 boiler) which has been in use since the 1950's. As a result, overall emissions of sulfur dioxide will be cut in half, and net emissions of nitrogen oxides and particulate matter will be reduced by more than 20%.

III. PROJECT OVERVIEW

A. General Description

The YCEP facility is a coal-fired CFB boiler cogeneration facility producing 250 MWe (gross) or 227 MWe (net). The power island consists of a Foster Wheeler Circulating Fluidized Bed (CFB) boiler and a "utility style" reheat turbine generator. The facility also includes a baghouse, a 395-foot stack, a cooling tower, coal unloading and enclosed 30,000 ton storage facilities, limestone unloading and storage facilities, enclosed ash by-product storage, and a demineralization system.

B. Technology Description

The facility will use eastern bituminous coal as its primary fuel in a Foster Wheeler CFB boiler. The steam produced in the boiler will generate 227 MW (net) of electricity in a Westinghouse turbine generator consisting of an opposed flow high pressure - intermediate pressure turbine element and a dual flow low pressure turbine element coupled to a surface condenser. A Process Flow Diagram is shown in Figure 1.

Emissions will be minimized through the use of the CFB boiler technology. Limestone will be injected into the boiler to capture sulfur dioxide ("SO₂"), reducing SO₂ emissions by 92%. Combustion air will be staged, combustion temperatures controlled, and aqueous ammonia will be injected into the cyclones to control nitrogen oxide ("NO_x") emissions. Carbon monoxide and hydrocarbon emissions will be minimized through the efficient combustion process which occurs

Adjacent to the boiler building is the turbine/hall building. This building houses the turbine/generator train and support systems, surface condenser, boiler feedwater pumps, and feedwater heaters. This building will be equipped with a maintenance bridge crane for servicing the major machinery within.

Other miscellaneous buildings on the site include the control/administration and maintenance building, coal unloading building, the ash leading building, and water treatment buildings.

IV. DETAILED PROJECT DESCRIPTION

A. Site Location

The approximately 38-acre site proposed for the YCEP cogeneration facility is located in North Codorus Township, York County, Pennsylvania (Figure 2). The parcel is bounded on the west by the P. H. Glatfelter Roundwood facility, on the south by Pennsylvania Route 116, and on the east and north by Kessler Pond and the mill pond (an impoundment of the west branch of Codorus Creek) and the west branch of Codorus Creek. The site is situated approximately eight miles southwest of York, Pennsylvania.

An existing rail line owned by Yorkrail, with a right-of-way through the P. H. Glatfelter property, is located just to the north of the proposed cogeneration site. Rail access would be provided to the YCEP site by construction of a new rail spur from the existing rail line into the YCEP facility. This new rail spur would provide for efficient coal delivery with minimal impact to the existing community transportation infrastructure.

B. Facility Description

The primary fuel supply for the proposed cogeneration facility would be United States eastern bituminous coal from western Pennsylvania and/or West Virginia. Run-of-mine (coal as produced at the mine) would be washed at the coal mine preparation plant, loaded into rail cars, and delivered to the YCEP site by rail. The washed coal would have a sulfur content of two percent or less. Propane would be used as supplemental fuel under limited circumstances (for example, during facility

in a circulating fluidized bed boiler. Particulate emissions will be controlled with a baghouse prior to the flue gas entering the stack.

The major new technology area involves the CFB boiler which will be the largest single train unit in the U.S. For large scale steam generator design, mechanical design requirements such as structural support, tube thickness, material selection, etc. and many process considerations such as steam/water circuitry design for natural circulation and steam superheating have been standard practice for many years. The main areas of scale-up for the subject unit are the processes related to fluidized bed combustion: furnace design, cyclone design, recycle heat exchanger design, and heat recovery area design.

In designing a large scale CFB furnace, the primary area of concern is to provide the conditions for optimum emission control, fuel burn-up, and heat transfer. These conditions can be achieved by providing good fuel, sorbent and air mixing, as well as the proper configuration of heat transfer surface. In designing a utility scale unit furnace, good fuel mixing for uniform fuel burning will be achieved by:

- Limiting the furnace depth so that fuel distance of travel from front to rear wall is minimized and good penetration and mixing of secondary air can be achieved.
- Telescoping the furnace width and adding more fuel, limestone, and secondary air feed points as well as the number of recycled solids return ports which uniformly distribute recycled solids and promote mixing.
- Adding a full division wall that distributes heat transfer surface for uniform heat removal.

Buildings and Structures

A main power island building will be constructed which consists of a number of adjacent or interconnected buildings, the largest of which will be the boiler building. This building will house the boiler combustor, cross-over, cyclones, air preheater, fuel day silos, primary and secondary air fans, and ash collection system. The building will be equipped with an elevator to facilitate maintenance.

startup when this supplemental fuel would be needed to operate the start-up burners in the CFB boiler to warm the CFB boiler prior to firing the coal fuel). The propane would be stored on-site in three 30,000-gallon horizontal tanks located north of the boiler baghouse.

An artist's rendering of the proposed YCEP cogeneration facility is provided in Figure 3 and the site plan is presented in Figure 4. These drawings show that project operations would be completely enclosed. Landscaping and berming would be incorporated into the facility design to screen ground level activities from Route 116. The new rail spur would be designed to ensure that rail cars delivering coal to the site are accommodated completely off the main line to eliminate potential impact to rail traffic on the Yorkrail line.

C. Plant Equipment Overview

Coal will be delivered to the site via unit trains roughly every 4 to 5 days at full facility capacity. The coal will be unloaded in an enclosed building and conveyed to storage silos for later use. Limestone will be delivered via truck and loaded pneumatically into storage silos for later use.

The boiler will use approximately 98.5 tons per hour of coal and 18.2 tons per hour of limestone to produce 2.1 mm lbs/hr of 2550 psig steam at 1005°F. The steam is sent to the "utility style" reheat condensing turbine which has a combined high and intermediate pressure section along with a low pressure section to produce approximately 250 gross MW of electricity. Of that electricity, 227 MW will be sold to Met-Ed under a power sales agreement.

Combustion gas produced by the boiler is sent through a baghouse where the gas is filtered and directed to the stack.

Boiler water treatment consists of pretreatment demineralization system. Pretreatment includes trains of dual media filters and reverse osmosis. The demineralization system includes three trains each capable of producing 500 gpm of demin water (total facility need is 1000 gpm). Each train consists of anion, cation, and mixed beds along with all regeneration equipment, regeneration waste neutralization equipment, chemical storage and injection equipment, and a 360,000

gallon storage tank.

The cooling tower will provide more than 100,000 gpm of water to the surface condenser along with additional minor flows to other facility uses.

The facility auxiliary power needs of approximately 21 MW will be met by the turbine/generator when the facility is operating. When the facility is down, Met-Ed can back feed the facility from the main step-up transformer.

Control, monitoring, optimization and load following, billing, guarantee administration and stack emission monitoring of the facility will be accomplished using a state-of-the-art distributed control system ("DCS").

Fire protection of the facility will be provided by an underground piping system which will service hydrant stations and sprinkler systems water will be provided from a fire water pump package taking supply from the Codorus creek adjacent to the facility. The pump package will be located so as to take water supply from the same intake structure as the existing PHG fire water and back-up water supply pumps.

Several off-site features are associated with the proposed YCEP project. These are:

- An electrical interconnection with the existing Met-Ed system: The primary electric interconnection proposed would be a single circuit 115 kV line which would interconnect with an existing Met-Ed 115 kV line. A secondary 115 kV double circuit line would extend north from the YCEP site across Codorus Creek and tie into an existing Met-Ed 115 kV line on the P. H. Glatfelter plant site.
- Connections to and from the P. H. Glatfelter Company's water and steam systems as shown below:

Interfaces include:

Line	To	From	Size	Distance, Ft ¹
600 psig Steam Supply/150 psig Start-Up Steam	PHG	YCEP	18"	3,000
Condensate Return	YCEP	PHG	8"	3,000
Cooling Tower Make-Up Water (PHG Wastewater)	YCEP	PHG	18"	9,200
Cogen Wastewater	PHG	YCEP	14"	7,400
Firewater	YCEP	PHG	10"	1,100
Back-Up C.T. Make-Up/Boiler Make-Up Water	YCEP	PHG	18"	1,400
Primary Boiler Make-Up Water	YCEP	PHG	6"	1,600
Potable Water	YCEP	Spring Grove Water Co.	6"	5,000

¹Distance from point of origin within YCEP facility to PHG termination point.

D. Detailed Equipment Descriptions

The following sections provide a detailed description of each of the major equipment groups.

1. Circulating Fluidized Bed Boiler Design

Fuel is fed to the base of the combustor along both the front and back walls and sorbent is fed to the base of the combustor along the front wall. Primary and secondary air flows to the combustor are provided by primary and secondary air fans. Before entering the combustor, these streams are preheated via heat exchange with the flue gases in the air heaters. The heart of the process is a circulating fluidized bed combustor in which the fuel is combusted while simultaneously capturing SO₂. Selective non-catalytic reduction of NO_x emissions is accomplished through injection of aqueous ammonia or urea at the inlet to the cyclones. Solid particles entrained by the upflowing gas in the combustor exit the top of the combustor into cyclones which efficiently separate the flue gas from the entrained particles. The flue gas discharged from the cyclone is directed to the downstream convective section of the boiler and the captured solids are recycled to the base of the ACFB by means of standpipes, J-valves, and an INTREXTM fluidized bed Integrated Recycle Heat Exchanger. The J-valves provide a seal between the positive pressure in the lower furnace

where the recycle solids are fed and the near ambient pressure in the cyclones. Refer to Figure 5 for an elevation of the CFB boiler.

Coarse ash material (bed ash) accumulating in the ACFB is removed from the bed using a specially designed directional grid and a fluidized bed stripper cooler. The bed ash is cooled by the fluidizing air flow to the stripper cooler. This heated air stream flows to the combustor along with the fines that are stripped out. The cooled bed ash will be conveyed to a bed ash silo. Fly ash collected in the air heaters, economizer, and baghouse hoppers will be pneumatically conveyed to the fly ash storage silo. Depending on the beneficial use for the by-product ash, the bed and fly ash streams may require additional processing to condition the ash.

Boiler feedwater is preheated in the economizer located in the convection heat recovery area. The preheated feedwater is then routed to the steam drum. From the steam drum, the pressurized water flows by natural circulation through the waterwall sections of the ACFB combustor and the INTREXTM heat exchanger. Steam generated in the waterwall boiling circuits is routed to the cyclone enclosure walls, the convection heat recovery area enclosure walls, the primary superheater, and then on to the intermediate and finishing steam coils located in the INTREXTM heat exchanger. This superheated steam flow is expanded through a high pressure steam turbine. A portion of the steam exiting the high pressure turbine flows through a reheater located in the convective heat recovery area. The reheated steam is expanded through an intermediate pressure steam turbine to extract additional power.

Thermal DeNO_x System

Low level emissions of NO_x generated by the oxidation of fuel nitrogen within the ACFB combustor will be further reduced by decomposing NO_x into N₂, O₂, and H₂O using non-catalytic reduction with ammonia. Aqueous ammonia or urea will be injected directly into the flue gas in the (4) ducts connecting the cyclones to the combustor. At this location, the temperature of the flue gas at 100% MCR will be approximately 1630°F. At this temperature the NO_x reduction reactions proceed at a sufficient rate to achieve a NO_x reduction level of 50%. Since staged combustion and low combustion temperatures already

contribute to significantly lower NO_x emissions than achieved with conventional pulverized coal boilers, extremely low NO_x emissions will be achieved by combining the two technologies.

Technical Challenges in Scale Up of ACFB Design

Evolution of ACFB Technology in U.S.

The size of the YCEP ACFB combustor represents a significant increase in scale over existing ACFB combustors. Currently, the largest single ACFB boiler is the 150 MWe Texas-New Mexico ACFB. This unit will be superseded in 1994 by the 165 MWe Point Aconti ACFB. However, when the YCEP project is started up in late 1997, it will become the largest ACFB combustor, capable of generating 227 MWe of net electrical power and up to 400,000 lb/hr of export steam. This scale will be most representative for potential utility-scale ACFB applications.

A significant challenge in the design of the single combustor ACFB for the YCEP project was to anticipate the influence that the scale of the combustor would have on its design and performance. The following sections will discuss several important considerations in designing a 227 MWe ACFB combustor having maximum certainty of successful operation. The major design features to be discussed include:

- Flexibility of Thermal Design
- Solids Mixing/Feed Distribution
- Cyclone Separator Design/Configuration

Design of ACFB Waterwall Surface

In scaling up the design of ACFB combustors, proper thermal design is important to control the temperature within the combustor. A properly designed ACFB combustor will operate at uniform 1600-1650°F temperatures, which will permit combustion to take place below the ash fusion temperature while providing optimal SO₂ capture with calcium-based sorbents and reduced NO_x formation. This is achieved by balancing the heat released by the

combustion process with the heat absorbed within the boiler. Heat absorption is achieved by withdrawing heat from the gas-solid suspension within the boiler, the cyclones, and INTREX™ heat exchanger. Adequate temperature control and solids distribution/mixing are essential to attaining high combustion efficiencies and minimal gaseous emission rates.

Since the fluidizing velocity of ACFB's is held constant, the cross-sectional area of the combustor increases proportionately with the firing rate. However, as the bed cross section increases, the ratio of bed volume per unit of wall heat transfer surface area increases. As the cross-sectional area increases for a unit of a given height, the amount of heat that can be removed through the waterwalls becomes a smaller fraction of the firing rate.

One method of obtaining the total required heat transfer surface is to increase the combustor height; however, the heat transfer surface that is introduced with added height is least effective at removing heat. This occurs because the rate of heat transfer varies with the solid suspension density and the solid suspension density in the YCEP combustor decreases rapidly with height until reaching a constant value in the upper furnace. This results in a more predictable heat absorption in the upper furnace. Furthermore, a lower density in the upper furnace results in less heat release, which is consistent with the lower heat absorption in the upper furnace.

In the YCEP ACFB design, the required amount of heat is removed through addition of a water-cooled, full division wall extending along the entire height of the combustor. This development introduces additional heat transfer surface throughout the entire furnace height. The division wall reduces the ratio of bed volume to the heat transfer surface area to a value that is typical of existing, smaller ACFB combustors.

Other advantages of the full division wall include:

- *More uniform temperature distribution in the ACFB.*
- *Lower unit height.*

Special design features included in the proposed furnace division wall include:

- *Pressure Equalization Openings*
- *Wear Resistant Design*
- *Provisions for Differential Thermal Growth*

Solids Mixing/Feed Distribution

Solid mixing plays an important role in determining the performance of ACFB combustors. As the combustor scale increases, changes in several design parameters can affect how well the fuel and sorbent are distributed in the combustor.

The factors which are thought to influence the degree of solid mixing in the lower region of ACFB's are placed in three categories: (a) mixing due to external solid recirculation, (b) mixing due to internal solid recirculation, (c) mixing limitations caused by solids feeder configuration and boiler dimensions.

Impact of Poor Solid Distribution

Nonuniform fuel distribution results in increased consumption of sorbent to achieve the same SO₂ emission level and may also increase the NO_x generation rate. With increased NO_x generation, NH₃ consumption increases to achieve the same level of NO_x emissions and the NH₃ slip (flow of unreacted NH₃) also increases. When burning coals containing chlorine, greater NH₃ slip increases the potential for NH₄Cl formation. Poor fuel distribution will also lead to a reduction in combustion efficiency through increased hydrocarbon and CO emissions, and increased calcination heat losses. Nonuniform fuel distribution may lead to oxygen deficient reducing zones that cause bed agglomeration and slagging problems, and may produce local hot spots within the combustor.

Cyclone Separator Design and Configuration

Another design issue important to the successful scale up of ACFB combustors is the design of the cyclone gas-solid separation system. As the size of the

combustor increases, the mass flow of gas and solids exiting the top of the combustor to the cyclones increases proportionally (given same particle size, combustor height, etc.). One method of performing this separation with the increased flow of particle-laden gas is to increase the size of the cyclone. Unfortunately, as the cyclone size (diameter) increases the centrifugal force field is reduced (at the same gas inlet velocity) and the particle collection efficiency deteriorates. In the absence of high solids collection efficiency, smaller sorbent, carbon, and ash particles escape through the cyclone rather than being recycled to the combustor with the cyclone underflow. This would result in inefficient fuel and sorbent utilization and a reduction in inventory of particles capable of circulating and transferring heat. Another drawback of increased cyclone size is that the increased cyclone height may dictate increased combustor height for the solids recirculation system to function properly.

To enable high gas-solid separation efficiency with the YCEP ACFB boiler design the size of the cyclones was held similar to that utilized in smaller units. However, to accommodate the increased gas flow rate the number of cyclones was increased.

2. Fuel and Sorbent Preparation and Feed System

Bituminous coal will be delivered to the site by rail and is stored in five 56 ft diameter coal storage silos with a 14 day storage capacity. The 2" x 0 size raw coal is then conveyed to crushers to be crushed to 1/2" x 0 size and stored in 4 in-plant coal silos. The crushed coal is extracted from the silos at variable rates, as required by the ACFB boiler, by gravimetric feeders and fed to both front and rear walls of the boiler. Equipment used includes: rotary car dumper, high angle conveyor, trippers, feeders and dust collection system.

3. Ash Handling and Storage

The CFB combustion process utilizes coal and limestone in the boiler. After combustion, the resulting limestone ash by-product material comes from two areas: bottom ash material from the CFB boiler and fly ash material from the baghouse. The bottom ash and fly ash material would be conveyed separately to on-site enclosed storage silos with a total capacity of approximately

3,100 tons. The ash handling system would include ash conditioning equipment located in the ash silo area. The ash conditioning equipment would be used to dampen the ash with water prior to loading it into totally enclosed 25 ton net capacity trucks in order to minimize the potential for fugitive dust emissions during ash handling. The trucks would be used to haul the ash material from the site to a surface mine reclamation site in Schuylkill County.

4. Baghouse

A multi-compartment baghouse filter system will be used to clean the flue gas exiting the primary and secondary air heaters. The baghouse filter system is designed to remove particulates in the flue gas and maintain particulate emissions below 0.011 lbs/MMBtu. A design air-to-cloth ratio of two is specified with one compartment isolated for cleaning and one compartment out for maintenance. Each baghouse compartment has a hopper which is heat traced and has an 4 to 8-hour storage capacity. The ash collected in the hopper will be discharged to the fly ash removal system.

5. Ash Handling System

The cooled bed ash will be conveyed to a bed ash storage silo via a pneumatic transport system. The bed ash collected during the pilot plant tests will be used to test different ash transport systems to determine the most reliable and cost effective transport system for the bed ash. The fly ash is conveyed from air heaters, economizer, and baghouse hoppers by dilute-phase pneumatic transport system to a fly ash storage silo.

6. Chemical Handling and Storage

As part of the proposed cogeneration facility operation, chemicals (for water treatment) and lubricants (for mechanical equipment upkeep) would be used and stored on-site. These materials would include oil and grease, diesel fuel, solvents (for degreasing equipment), caustics and sulfuric acid, water treatment chemicals, and aqueous ammonia.

Aqueous ammonia (29 percent solution) would arrive at the facility by truck at an estimated frequency of one delivery per week. The ammonia storage tank would be located within a fully contained and diked concrete area providing sufficient secondary containment of the storage tank to prevent a release.

7. Limestone Handling and Storage

Pulverized limestone would be delivered to the facility in 20-ton capacity enclosed trucks as well as via rail. Suppliers are expected to be generally located within a 50-mile radius of the proposed site, with one potential source located approximately 100 miles from the site. The limestone material would be pneumatically (air blown) transferred from the trucks or railcars into a storage silo. The silos would be sized to provide an approximately five-day supply of limestone (1,870 tons). The limestone material would then be pneumatically transferred from the storage silo to the day bins in the boiler house. From the day bins, the material would be fed directly into the CFB boiler for use in SO₂ emissions control. By transferring the material via enclosed systems the potential for fugitive dust emissions would be minimized.

8. Turbine

The YCEP facility will generate electric power by extracting shaft work from the high pressure superheated steam flow produced by the ACFB steam generation circuits. The turbine generator system includes high, intermediate and low pressure steam turbines connected to a generator. The turbine will be equipped with 8 extraction points to service the feedwater heaters, reheat system, and export steam. Export steam (up to 400,000 lb/hr) at 575 psig and 670°F will be sent to PHG where it will be integrated with their existing steam system. The Westinghouse turbine-generator includes 285 MVA, H₂ cooled generator, and brushless excitation.

9. Draft System

The ACFB boiler is equipped with one (1) 100% capacity centrifugal primary air fan, one (1) 100% capacity centrifugal secondary air fan, two (2) 100% capacity centrifugal INTREX™ heat exchanger blowers, two (2) 100% capacity

positive displacement J-valve blowers, four (4) 50% capacity positive displacement sorbent blowers. The primary air and the secondary air are heated by the flue gas in two heaters arranged in parallel with multiple air and flue gas passes. With flue gas flowing on the inside of the vertical tube, the gas side cleanliness is maintained without steam soot blowing. Balance furnace draft is maintained by one (1) 100% capacity centrifugal induced draft fan. Part of the primary air bypasses the primary air heater and is used to fluidize the stripper/coolers and provide seal and sweep air for the fuel feeders part of the high pressure air from the J-valve blowers is injected into the transfer lines from the combustor to the stripper/coolers to assist solids movement into the stripper/cooler.

E. Pollution Control

The proposed facility includes a single coal-fired CFB boiler equipped with state-of-the-art air pollution control equipment. Since the facility would be subject to Prevention of Significant Deterioration (PSD) regulations, the regulated level for these air pollution controls would be determined through a Best Available Control technology (BACT) analysis. In addition, the YCEP site is located in the Northeast Ozone Transport Region established by the CAAA and would therefore be required to offset any NO_x emissions at a ratio of 1.15 to 1. The facility also would be required to complete a Lowest Achievable Emission Rate (LAER) performance test to demonstrate whether the proposed facility can meet a lower NO_x emission level. Both the BACT analysis and the NO_x offset plan approvals would be conducted as part of the facility's PSD air quality permit application process with the Pennsylvania Department of Environmental Resources (PADER).

The proposed air pollution control equipment would include the following:

- A minimum of 92 percent SO₂ emissions control would be achieved through the design of the CFB boiler system. The inert limestone in the boiler combustion chamber would interact with the SO₂ emitted in the coal burning process to control the SO₂ emissions level.
- Aqueous ammonia injection technology known as selective non-catalytic reduction (SNCR) would be employed to minimize NO_x emissions. In this process, aqueous

ammonia or urea is injected into the boiler exhaust gas to convert NO_x into nitrogen and water. The NO_x emissions reduction level being proposed would be guaranteed by the boiler manufacturer to achieve a 40 percent or greater reduction in NO_x emissions at 0.125 pounds per million Btu or less.

- A fabric filter collection system (baghouse) would be used to control particulate emissions to 0.011 pounds per million Btu (lbs/MMBtu). The baghouse would remove the fine particles in the boiler exhaust stream prior to release of the exhaust gas into the atmosphere.
- The facility would also be equipped with a continuous emissions monitoring (CEM) system located in the stack, downstream of the pollution control equipment. The CEM would monitor exhaust gas flow, SO₂, NO_x, opacity, and either carbon dioxide (CO₂) or oxygen (O₂). This CEM system would be used to assure that the facility is in constant compliance with the air quality permit approval.

In addition, the facility would be designed to minimize fugitive emissions associated with coal, ash by-product, and limestone materials handling through the maximum use of enclosures.

F. Facility Water Usage

The proposed cogeneration facility would have several different uses for water within the facility. During facility construction, the projected water use is expected to range from 5,000 to 15,000 gallons per day (gpd). YCEP's external water needs will be satisfied primarily from the P. H. Glatfelter Company and Spring Grove Water Company. Further details with regard to facility water supply are provided below.

Process Water

The proposed YCEP facility would supply up to 400,000 pounds per hour of high pressure steam to the P. H. Glatfelter Company and provide 100% condensate return. Process water losses from the steam system, water treatment and boiler blowdown (i.e., discharge) would be compensated for by using water supplied from

the P. H. Glatfelter process water system. The average flow would be approximately 200,000 gpd of additional water transferred from the P. H. Glatfelter Company's process water system to make up for these operating losses.

Cooling Water

Cooling water system make-up requirements for the proposed YCEP facility would be supplied from the P. H. Glatfelter wastewater treatment plant secondary effluent discharge located on the eastern side of the paper mill's property. Consumption of this water would vary based upon ambient conditions, plant production levels and cooling water quality.

A pilot plant program was used to determine the water treatment program which would be needed to allow for the reuse of the P. H. Glatfelter secondary treatment plant effluent stream in the cooling tower. Based on the pilot plant operation, as well as-available data and information on other similar water treatment programs, the YCEP water treatment program would be limited to a disinfectant, a chemical dispersant, and sulfuric acid. A material such as bromine, chlorine dioxide, chlorine gas, or hypochlorite (liquid bleach) would be used as a disinfectant to prevent build-up of algae in the recirculation water; the chemical dispersant would be used to limit scale formation on the cooling water system components (heat exchangers, piping, pumps); and sulfuric acid would be added to assist in controlling corrosion and scaling on cooling water system components and maintain the water pH within acceptable limits for discharge to the P. H. Glatfelter secondary treatment plant. This water treatment program would be placed directly in the cooling tower recirculation water system.

The expected usage of secondary treatment plant effluent for cooling tower incoming water would be 4.1 mgd. This expected usage is during the periods when maximum evaporation is taking place in the YCEP cooling tower. Of this incoming water, 2.5 mgd would be evaporated in the cooling tower operation and 1.6 mgd would be returned to the P. H. Glatfelter secondary treatment plant as cooling tower blowdown. This blowdown stream would be at a cooler temperature than the secondary effluent incoming water stream due to the cooling effect in the cooling tower operation.

G. DOE Clean Coal Technology Program Demonstration Tests

This demonstration program is designed to provide the following important information:

- Demonstrate unit start up and shut down capabilities and provide data and experience on ACFB boiler operation during these transients.
- Demonstrate ACFB boiler dispatching capabilities and constraints.
- Demonstrate ACFB boiler operation at full-load conditions for extended periods and continuous operation at part-load conditions.
- Provide quantitative results from a systematic study on the effects of important operating parameters and fuel characteristics on boiler performance which will aid in the optimum economic design and operation of future units.
- Identify constraints governing fuel selection based on test results from four different fuels.
- Provide guidelines for inspection and maintenance along with information on maintenance costs.

Included in the test program are specific operating tests to evaluate the effects of the following operating parameters on ACFB performance:

- Fuel size and quality
- Sorbent size and quality
- Fuel and sorbent rates
- Combustor temperature
- Excess air
- Primary/secondary air ratio

Specific boiler performance parameters to be quantified include:

- Boiler thermal efficiency
- Steam/Electrical Generation Capacity
- Ability to control steam temperature and pressure
- Ash production and quality
- Bed ash/fly ash split
- Unburned carbon losses in bed and fly ash
- Stack emissions: NO_x, SO₂, CO, VOC and particulate
- Power consumption of auxiliary equipment
- Percent SO₂ capture and Ca/S ratio
- Control of bed inventory
- Combustor temperature profile

Tests are proposed for four different coals: the design coal (basis for combustor design) and three test coals having different properties from the design coal. The purpose of performing tests with coals having properties which differ from the design coal is to determine what range of coal properties can be utilized and the impact of fuel characteristics on the performance and operating economics of the ACFB.

In addition to performing tests at 100% maximum continuous rating (MCR), tests would be performed to demonstrate operation of the boiler and other ACFB system components during start-up, shutdown, and dispatch of the facility. To demonstrate the capability of the system, a 30-day test with the boiler operating at a minimum of 96% MCR is proposed.

V. PROJECT STATUS AND SCHEDULE

The YCEP is currently in the final stages of permitting. Final Land Development Plans are currently being submitted and reviewed, the PA DER is in the review phase of the air permit, and the US DOE is on schedule with the NEPA process. Therefore, Air Products is currently planning the engineering work ahead. This section highlights some of the work currently underway (during calendar year 1994). First, we discuss the selection of the execution team (A/E and CM), follow with some preliminary engineering activities and conclude with a review of our project execution schedule.

1. Selection of Execution Team

- a. Engineering (A/E) firm: APCI engineering personnel including Operations input will lead the engineering of the facility. All plot plans, schedules, design criteria, vendor selection and P&ID will be the primary responsibility of the Air Products team. The A/E firm will be the major resource to implement these. The A/E will also have the primary responsibility for production of all the design drawing packages and detailed design and engineering decisions. Purchasing will be led by an Air Products employee and will electronically feed into Air Products accounting, billing and tracking systems. Most of the resource to actually implement purchases will come from Gilbert.
- b. After extensive review of suitable firms, Air Products selected Gilbert/Commonwealth of Reading, PA as the A/E. Gilbert is located in close proximity to Air Products offices, Foster Wheeler's offices and to the York site. Gilbert brings power plant design and project execution expertise and a compatible culture to that of Air Products. We intend to open an independent office located between Allentown and Reading in which all project work will be executed. This will focus all team members on the specific goal of the project, without outside distractions.

2. Construction Management (CM) Selection Process

- a. Integrated Team Approach: Although Air Products has a successful history of managing construction projects itself, the magnitude of the YCEP project dictates that outside resources are required. The approach will be an integrated construction management team employing some APCI employees but staffed mostly by an outside Construction Manager.
- b. Selection Process: APCI interviewed several CM firms and is currently reviewing candidates. Selection will be based on expertise and experience, compatibility with APCI, and price. It is expected that the CM team start well before the first site work. The team will review constructibility, work breakdown structures, construction schedules, and bid document requirements.

3. Foster Wheeler Preliminary Engineering

Foster Wheeler has been kicked off to perform some preliminary engineering including confirmation of circulation rates, heat transfer calculations, mechanical engineering work on the division walls, higher definition on the refractory scope, auxiliary equipment specification and bid. Foster Wheeler will also develop a detailed schedule during this phase and assist in APCI's construction planning activities. In addition, Foster Wheeler and Air Products are evaluating several air heater designs and vendors, and will produce preliminary general arrangements.

4. Other Engineering activities during 1994

Final plot plans and construction access and laydown drawings are being developed. Final land development approvals and erosion and sedimentation plan approvals are also underway during mid 1994. Final General Arrangement drawings showing all buildings and equipment will be developed by Fall 1994. System specifications indicating design criteria, level of redundancy and off design operating parameters as well as P&ID's will also be developed by Fall of 1994. Finally, most major equipment will be bid and evaluated prior to 1995.

5. Execution Schedule Development

One major activity during mid 1994 is the development of a detailed critical path project execution schedule. Since boiler supply and erection is on the critical path, initial efforts have gone into understanding the delivery and erection sequence of the boiler. We have identified shipping sizes and loads as well as several potential erection sequences. We have based our information on discussions with Foster Wheeler, boiler contractors, other owners, construction management firms and our other CFB projects.

The schedule is shown in Figure 6. It is based on issuance of the air permit and record of decision by 1 January 1995 and shows a commercial operation date of 1 January 1998. We are currently analyzing the schedule to investigate the costs/benefits of schedule acceleration.

FIGURE 1. PROCESS FLOW DIAGRAM FOR YCEP COGEN FACILITY

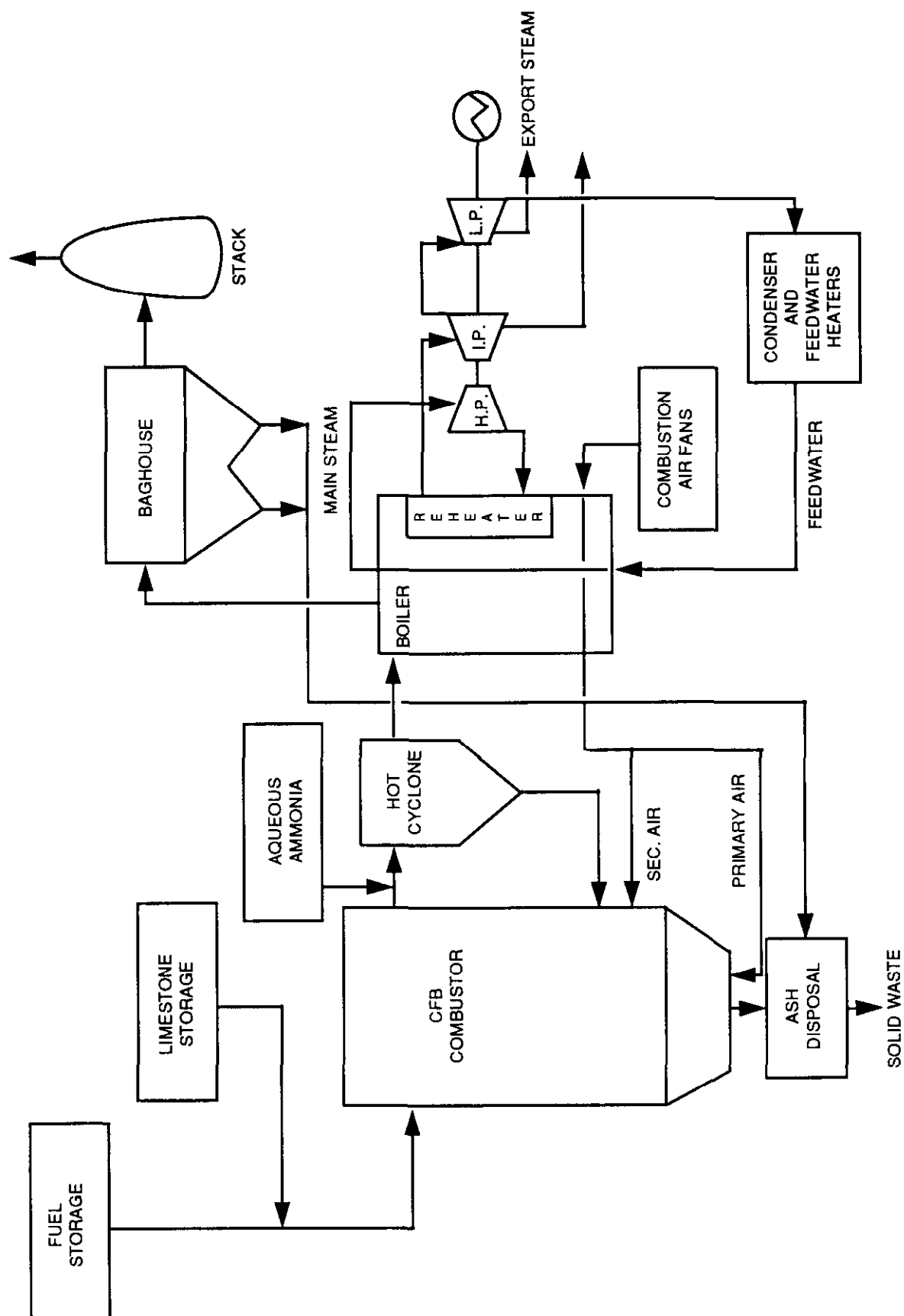
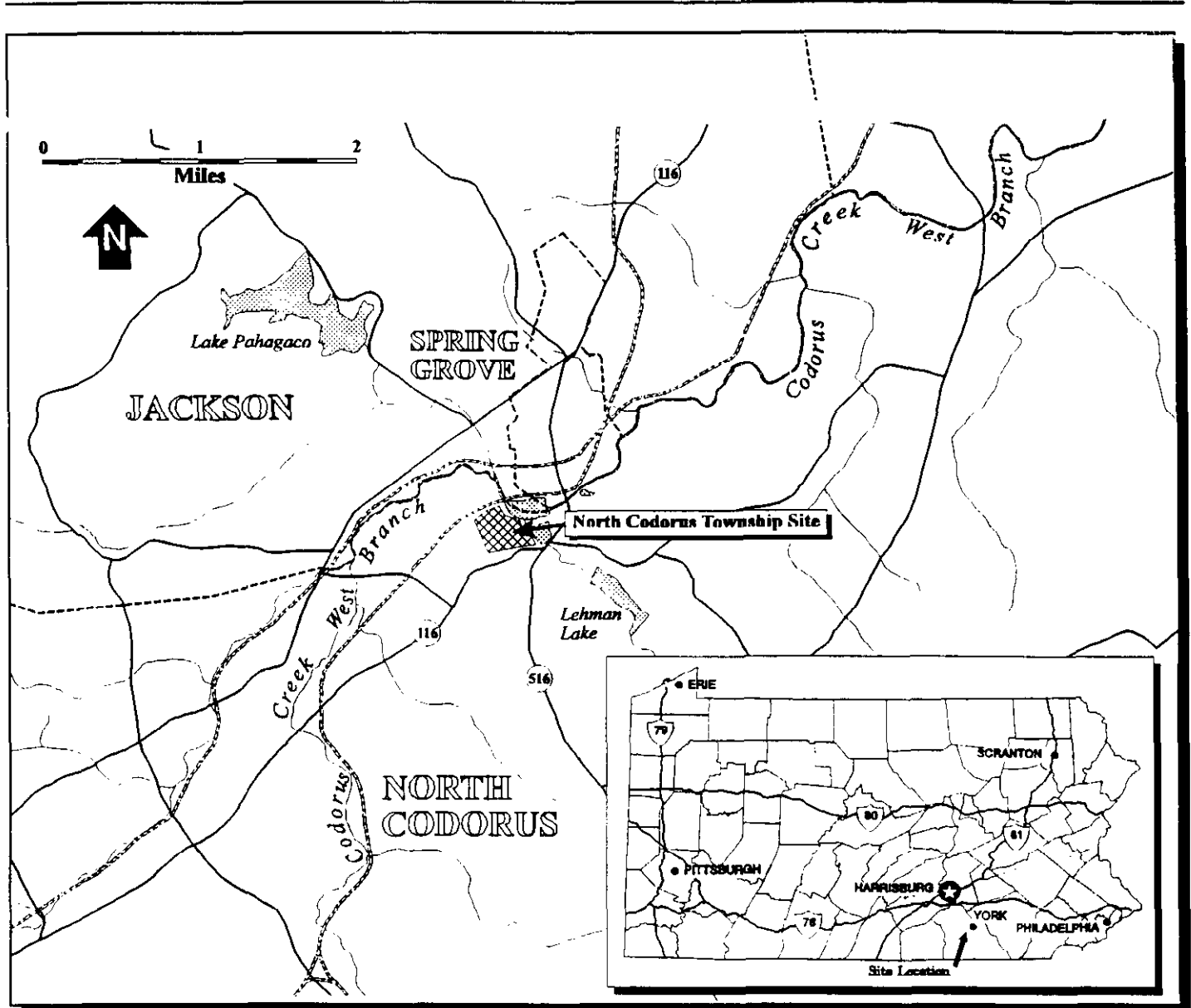
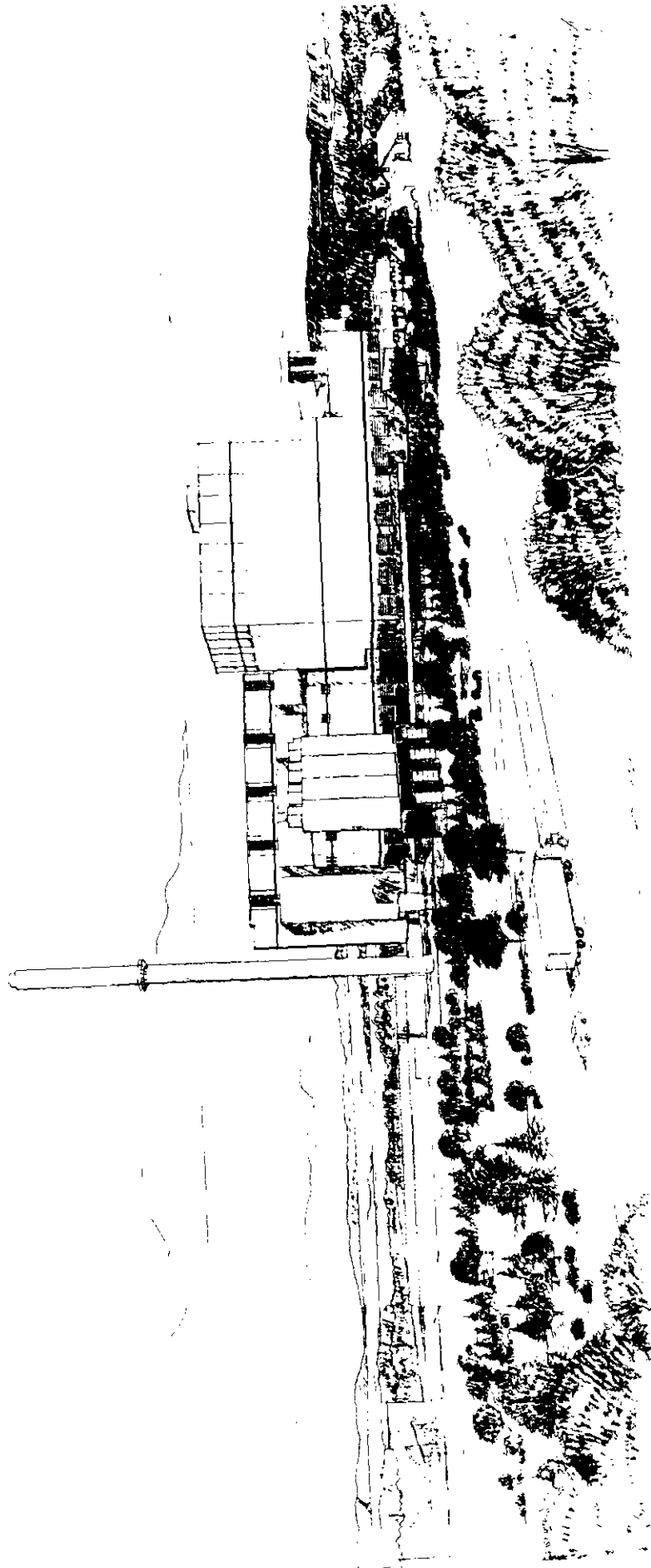


FIGURE 2

Site Location Map



Regional map showing the North Codorus Township location of the proposed YCEP Cogeneration Facility.

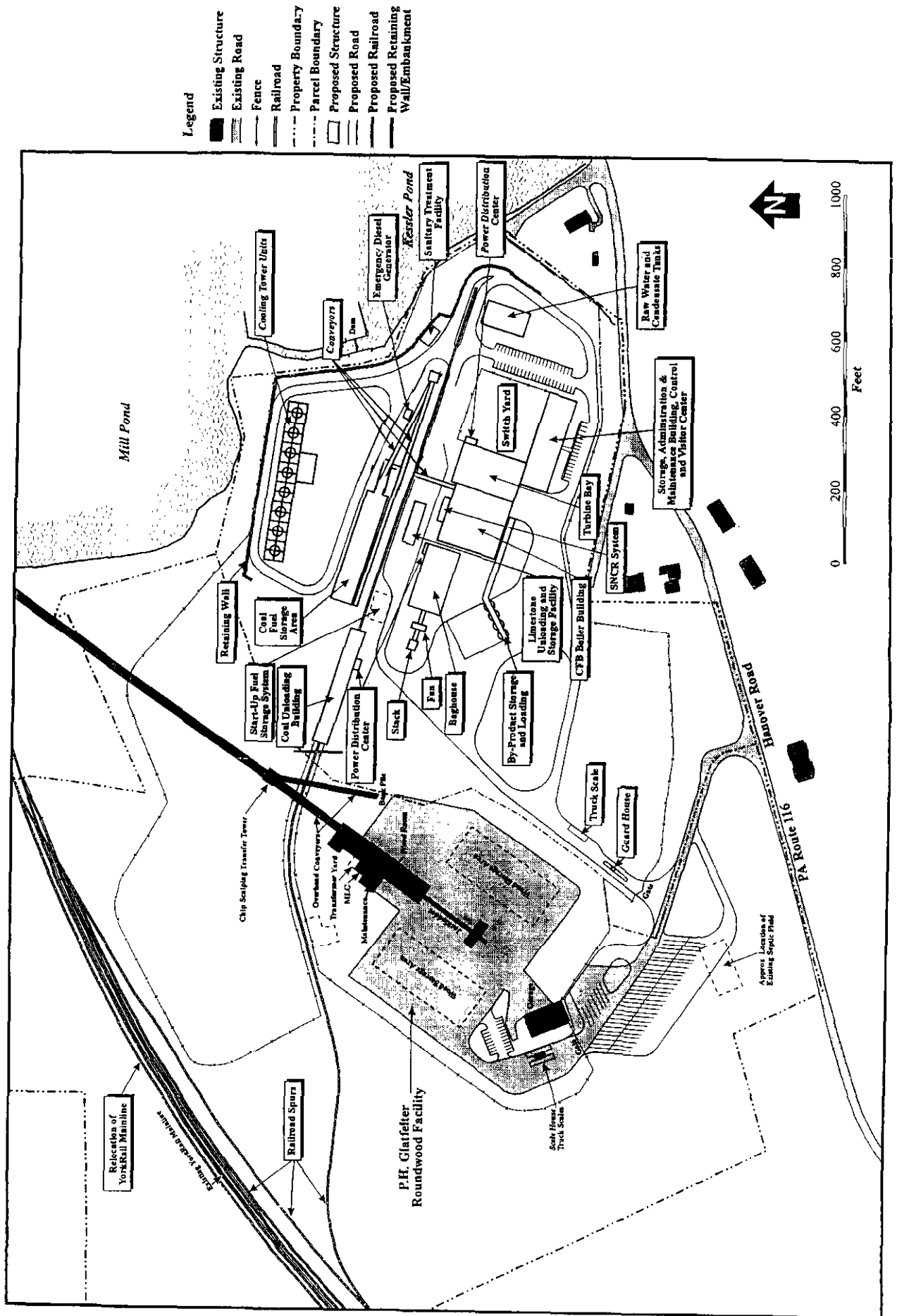


York County Energy Partners
Proposed Cogeneration Facility

NORTH CODORUS TOWNSHIP SITE

FIGURE 3
Artist's Rendering of
YCEP Facility

FIGURE 4
Site Plan



YORK COUNTY ENERGY PARTNERS PROJECT

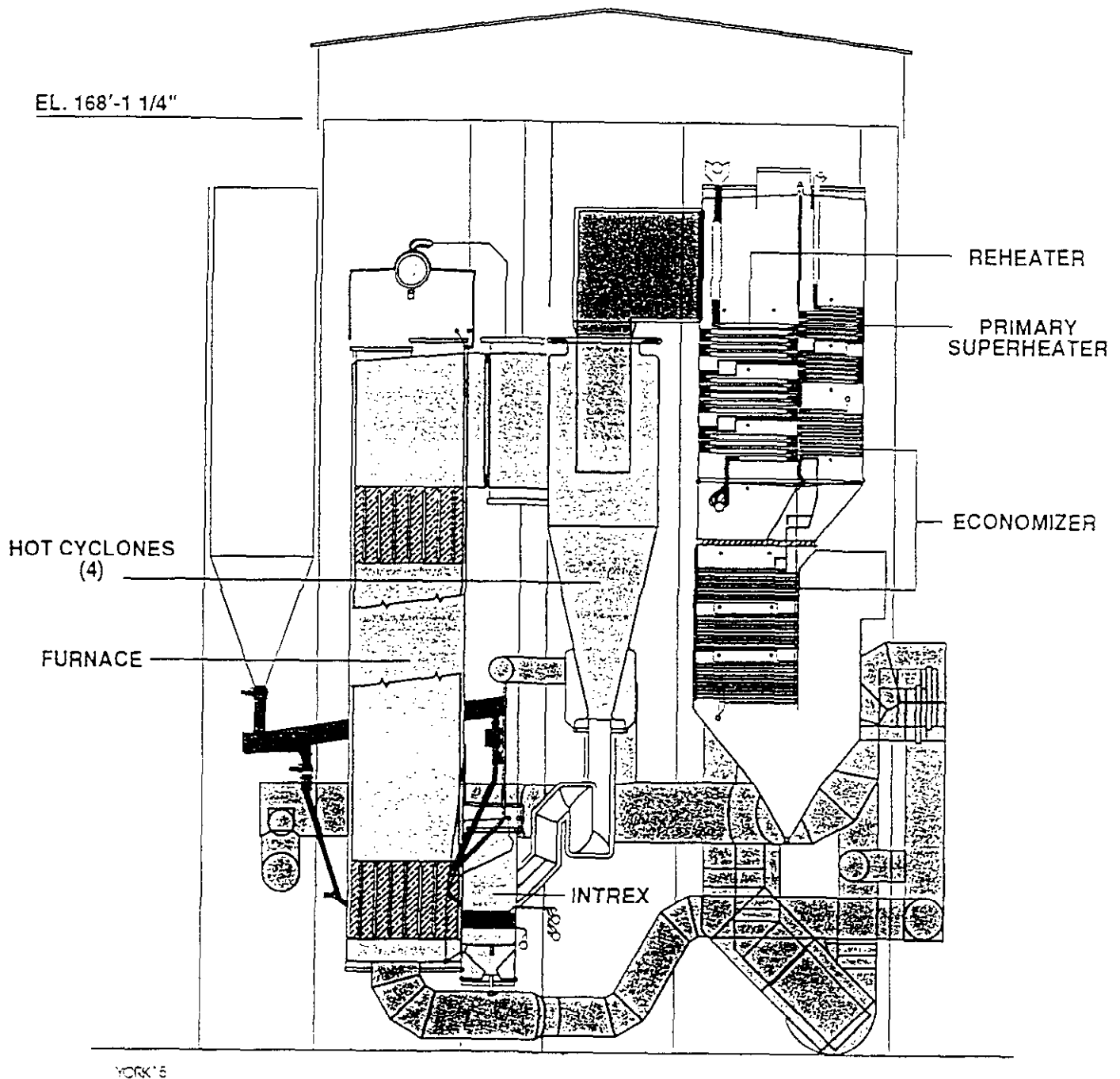
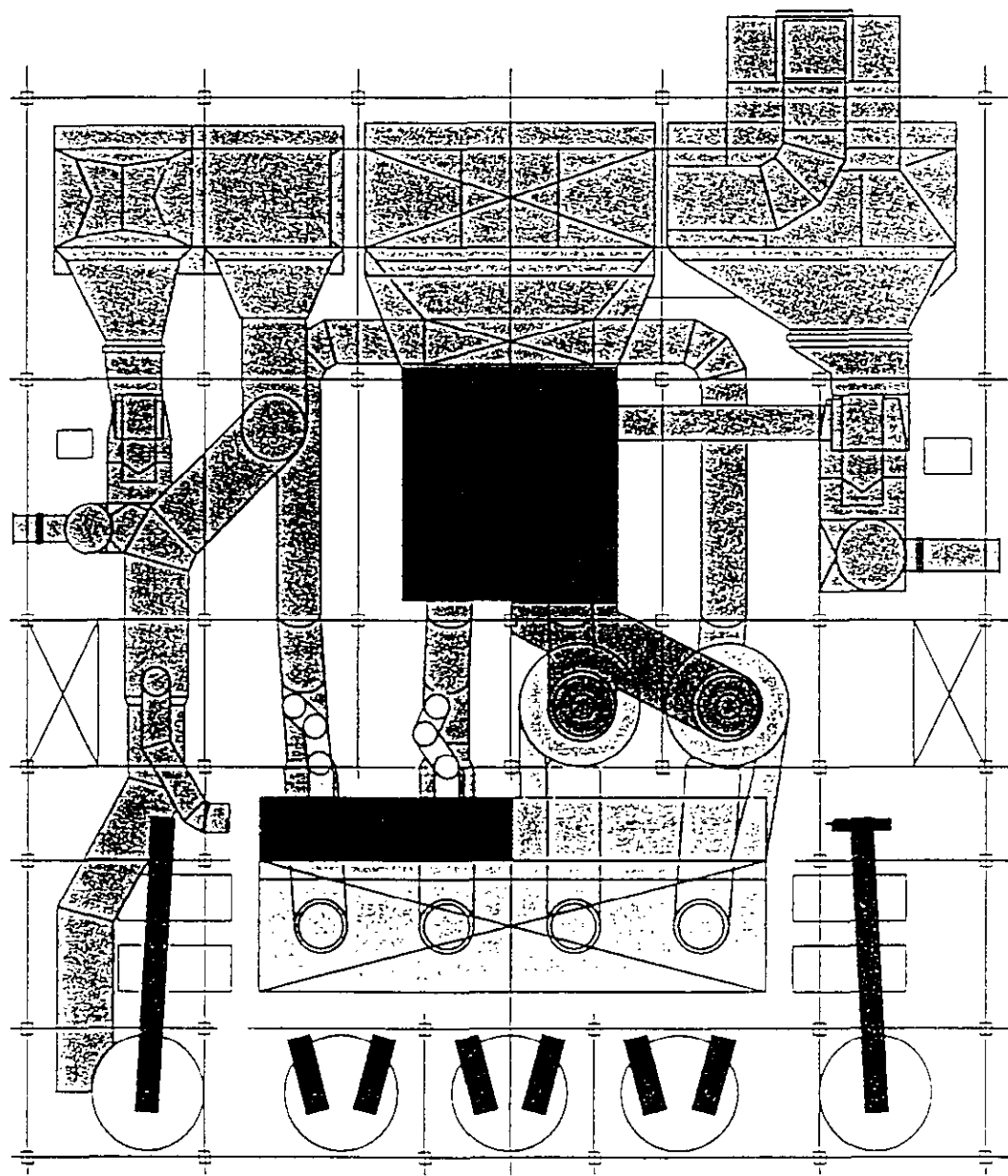


FIGURE 5A

YORK COUNTY ENERGY PARTNERS PROJECT



W 4X16

FIGURE 5B

FIGURE 6
PROJECT SCHEDULE

Receive PSD Air Quality Permit	February 1995
Complete NEPA Process	March 1995
Commence Site Work	March 1995
Financial Closing	May 1995
Complete Site Work	August 1995
Erect Boiler Steel	November 1995
Erect Baghouse	June 1996
Erect Turbine/Generator	October 1996
Energize Switchyard	August 1997
First Fire	September 1997
Anticipated Commercial Operation Date	January 1998

DMEC-1
PRESSURIZED CIRCULATING FLUIDIZED BED
DEMONSTRATION PROJECT



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ABSTRACT

Midwest Power, Dairyland Power Cooperative, Pyropower Corporation (a subsidiary of Ahlstrom Pyropower Inc.), and Black & Veatch have joined with DOE to demonstrate Pyropower's PYROFLOW® Pressurized Circulating Fluidized Bed (PCFB) technology. The project known as the DMEC-1 project was selected by DOE for \$93,253,000 of funding in the Clean Coal Technology Program Round III solicitation and the Cooperative Agreement was awarded in August of 1991. The project is currently in the first budget period and a number of engineering and economic evaluations have been completed to refine the project technical design and cost baseline. This paper will describe the project and discuss the results of the evaluations and design efforts completed to date.

PROJECT GOALS

The goals of the project are to demonstrate that the PCFB technology can provide an environmentally clean, efficient and cost-effective means of producing electricity. Specific goals of the project are to demonstrate:

- Lower capital costs compared to competing conventional technologies
- High efficiency
- Hot gas cleanup technology
- Low levels of NO_x, SO_x, and CO emissions
- Simplified load following

TECHNOLOGY DESCRIPTION

The PCFB technology is a combined cycle power generation system that is based on the pressurized combustion of solid fuel to (1) generate steam to a conventional Rankine cycle combined and to (2) expand the hot pressurized flue gas through a gas turbine in a Brayton cycle.

Figure 1 shows a simplified schematic of the cycle. Combustion air is supplied from the compressor section of the gas turbine to the PCFB combustor located in a pressure vessel. Coal and sorbent are mixed with water to form a paste which is pumped into the combustion chamber using a piston-type pump commonly used in the concrete industry. Combustion takes place in a fluidized bed at approximately 1600° F and 150-240 psia. Flue gases exit the combustor through a cyclone and are directed to a filter system where particulate removal takes place. The hot, clean gas is expanded through the gas turbine before passing through a heat recovery unit and the exhaust stack. Heat recovery takes place in the combustor and the heat recovery unit and steam is generated to power a steam turbine generator. Approximately 20-25% of the power output comes from the gas turbine with the remaining 75-80% from the steam turbine.

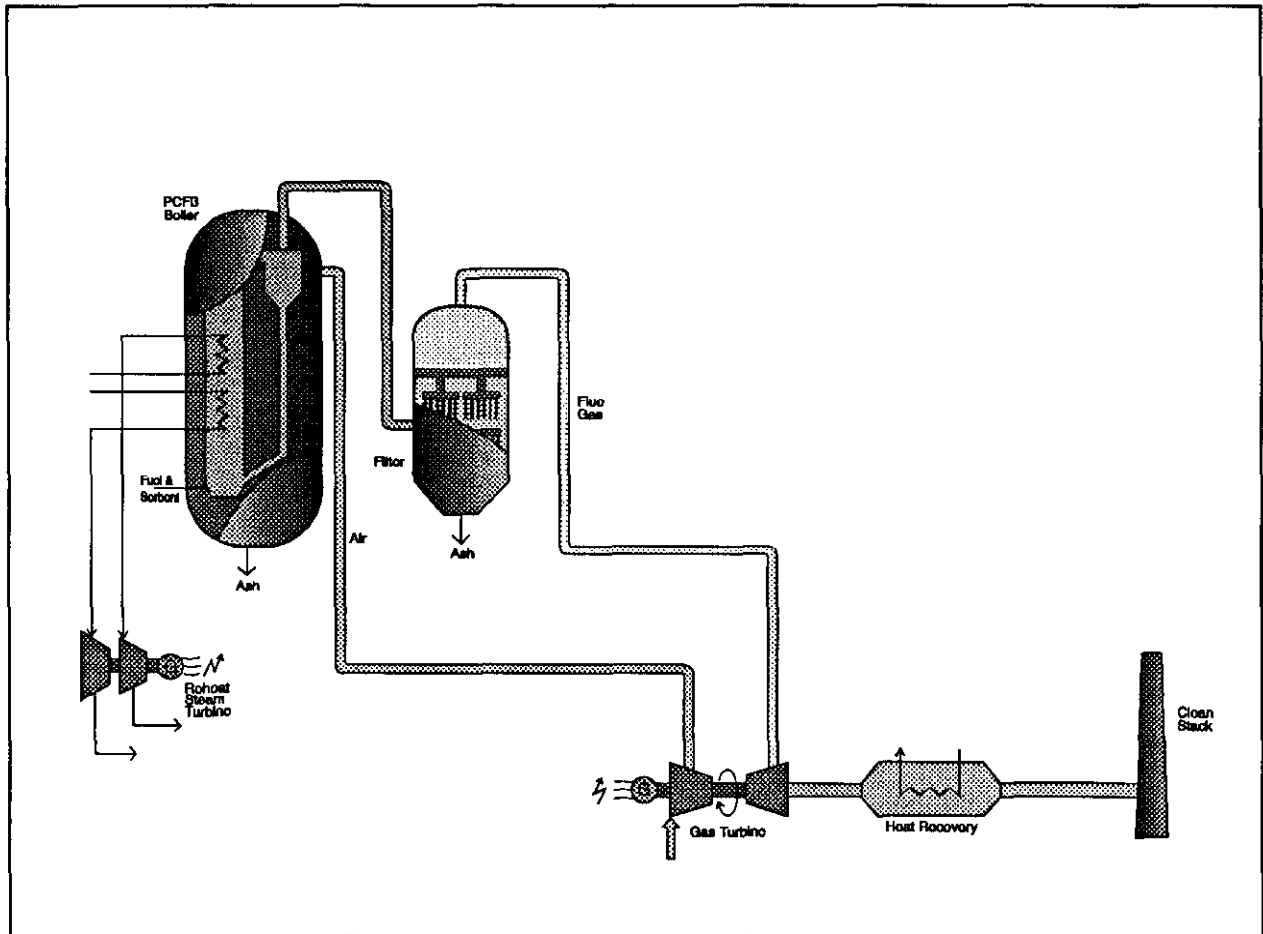


Figure 1- PCFB Simplified Schematic

Air enters the pressure vessel at the top, first providing cooling to the vessel. It is then introduced as primary air through a fluidizing grid in the bottom of the combustor and through secondary air injection points above the grid. This method of air introduction to the combustor serves to provide lower NO_x emissions as well as assistance with load following control. Bed ash is removed from the bottom of the boiler where it is cooled and depressurized in the ash removal system. The finer particles are carried by the flue gas to the hot cyclone where they are captured and returned to the boiler via a loop seal. The very finest particles, which are fully reacted, exit the cyclone with the hot gases.

Gas velocity in the boiler is approximately 15 feet/second. Continuous mixing throughout the boiler provides for a constant temperature throughout, promotes complete combustion and enhances the chemical reactions with the sorbent for SO_2 removal. The lower section of the boiler is refractory

lined. The heat generated is transferred to the water walls and to the superheat and reheat surfaces. The superheat and reheat elements are constructed of Pyropower's Double Omega design which affords reduced susceptibility to erosion damage.

The flue gases leaving the hot cyclone pass through a ceramic barrier filter for particulate removal. The filter removes the fly ash from the flue gas to very low levels which meets the operating requirements of the gas turbine and is below existing environmental standards. A particulate emission level below .041b/MMBtu is predicted. The solids are inert and safe for use or disposal.

The gas turbine is a standard single shaft industrial machine configured to allow for external combustion as the energy source. The turbine is coupled to a generator to provide a portion of the electrical output of the plant. Remaining useful heat is recovered from the gas turbine's exhaust for preheating feedwater.

DEVELOPMENT HISTORY

Karhula Testing Facility

The Karhula PCFB Testing Facility was built in Karhula, Finland to support the design and operation of commercial first generation and advanced PCFB units. In 1989, Ahlstrom, the parent company of Pyropower, initiated operation of the Karhula PCFB facility. It is an integrated PCFB unit, including the key components and mechanical design features that will be utilized in commercial plants. These includes complete fuel preparation systems, sorbent injection systems, pressurized furnace with heat transfer surfaces, hot cyclone, hot gas filter, ash cooling and depressurization systems and testing of materials and coatings for gas turbine components. The operating conditions of pressure, temperature, fluidizing velocity, heat transfer rates, and residence times are similar to a commercial size plant.

The test facility is designed for the following operating conditions:

- Heat Input 34MMBtu/hr

- Fuel feed rate 15870 lb/hr
- Gas flow rate 43650 lb/hr
- Operating Temp. 1616 °F
- Operating Pressure 232 psia

Testing Program Results

In support of the project, design verification activities have been conducted at Karhula. These activities can be subdivided into two primary areas of interest; PCFB combustor performance and ceramic filter testing.

In regard to the ceramic filter testing, a test program is underway at Karhula to test the Westinghouse ceramic candle filter technology in integrated operation with the PCFB pilot plant. This program which has been cosponsored by Pyropower, Westinghouse, American Electric Power, EPRI and DOE and has included the testing of Coors mullite candles and Refractron silicon carbide candles. Over 2000 hours of filter operation has been achieved on a variety of coals.

PCFB combustor performance in terms of combustion efficiency and emission control has exceeded initial expectations. Testing has been conducted on a variety of different coals including two of the design coals for the project, a low sulfur Wyoming sub-bituminous coal and a high sulfur Illinois No. 6 bituminous coal. In total, over 3500 hours operation on coal has been achieved in the pilot plant.

Test data indicates carbon conversion efficiencies between 99.8 and 100% from approximately 40 to 100% load for both the design coals. This data was obtained with combustion temperature ranging from 1500° - 1600°F and with excess air levels of from 4 to 30%. This excellent performance is attributable to the excellent mixing characteristics of the PCFB and the high partial pressures of oxygen inside the combustion chamber that occurs under pressurized conditions.

Impressive sulfur removal capability has also been demonstrated in the pilot plant for both the high sulfur and low sulfur coals. In order to achieve 90% SO₂ removal, a Ca/S molar ratio of approximately 1.1 is required for the high sulfur coal while the low sulfur coal requires a Ca/S molar

ratio of about 1.5. At slightly higher calcium sulfur ratios, 98-99% SO₂ removal has been demonstrated even for the low sulfur Wyoming coal.

NO_x emissions have shown a strong dependency on excess air levels. However, operating at design excess air levels and using staged combustion results in NO_x emissions that are well below current Federal standards. Ahlstrom Pyropower has also successfully used ammonia injection to provide non-catalytic reduction of NO_x emissions where very low NO_x emissions are required (~0.1 lb/MMBtu). This same technique has also been shown to be very effective for pressurized conditions and emissions as low as 0.04 lb/MMBtu have been demonstrated in the pilot plant.

Demonstration Project Developments

The demonstration project will seek to prove the results obtained at the Karhula testing facility at a commercial scale. In addition, the demonstration project will include the following features not included at the pilot plant:

- Integration of gas and steam turbines with the PCFB combustor systems
- Integration of the control of the PCFB with the gas turbine and electrical generator systems
- Full scale paste preparation and handling systems and ash removal and handling systems

ENGINEERING AND ECONOMIC EVALUATIONS

Several engineering evaluations have been done to support Midwest Power's least-cost resource planning requirements. These have included the following:

- Evaluation of reuse or replacement of the steam turbine
- Evaluation of several steam and pressure designs for the steam cycle
- Modeling of the site conditions for air quality permitting considerations
- Sensitivity studies of availability, capital cost, and maintenance cost variations

Configuration Studies

The preliminary engineering was completed on an 80MW non-reheat repowering configuration and the results of this was reported in a DOE Topical Report [3].

Studies were done to determine if project economic enhancements could be achieved by improving power output and improving plant performance. The cases studies compared gas turbines with modified or standard compressors. Previous testing of steam turbine considered for repowering had identified the steps needed to refurbish the turbine and the associated costs. Budget estimates were obtained for a similar new steam turbine as well. In addition, a new turbine with higher pressure steam conditions along with the needed modifications to the PCFB to accomodate these higher pressures was evaluated.

In the project economic evaluations, operating and maintenance costs developed in EPRI's study of Ahlstrom Pyropower's PCFB were used [4].

Evaluation of sites within the Midwest Power System was also done to satisfy regulatory requirements as well as to identify any other potential project economic improvements due to differring fuel, transportation, or transmission costs. As a part of this review the environmental characteristics of each site was evaluated as well.

Evaluation Results

These studies and analyses indicated that to meet Midwest Power's least-cost planning objectives, project restructuring is needed. As a result of this Midwest Power has petitioned the DOE to change the project to a nominal 150 MW size at a Midwest Power site in Council Bluffs, Iowa with a startup date in 1998/1999.

PROJECT SCHEDULE

Evaluation of the project configuration and schedule continues. The current and proposed project

schedules are illustrated in Figure 2.

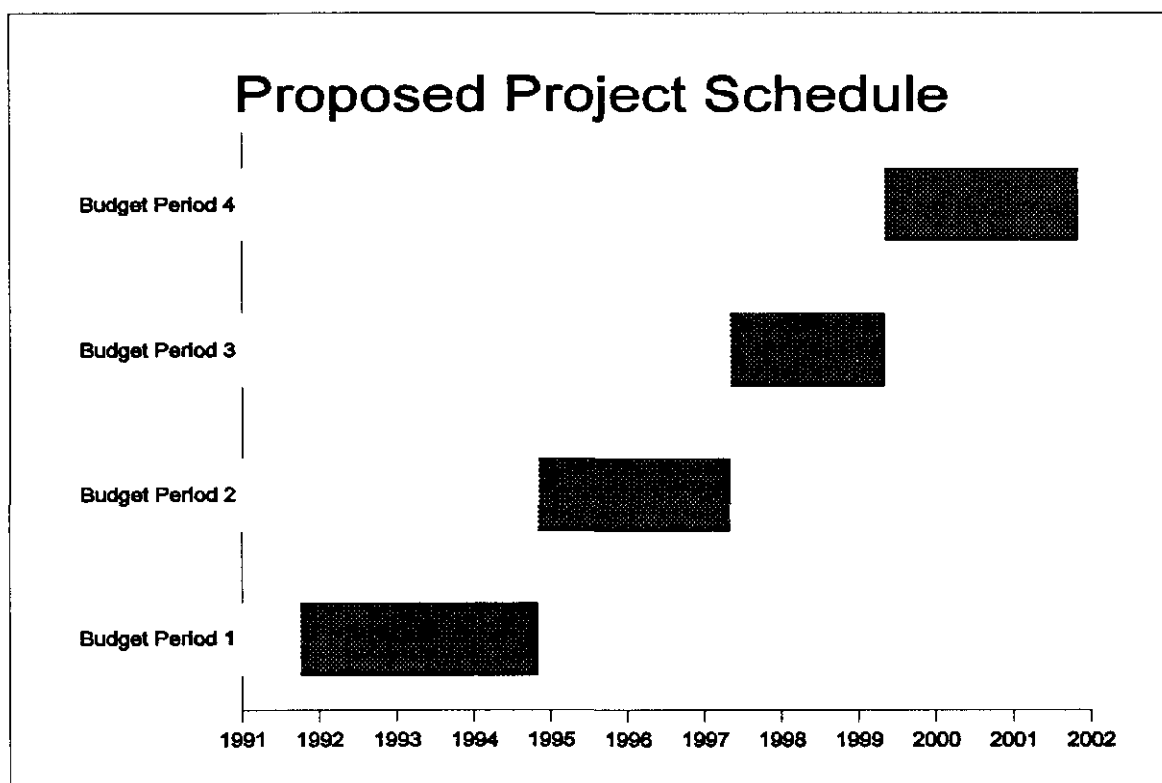
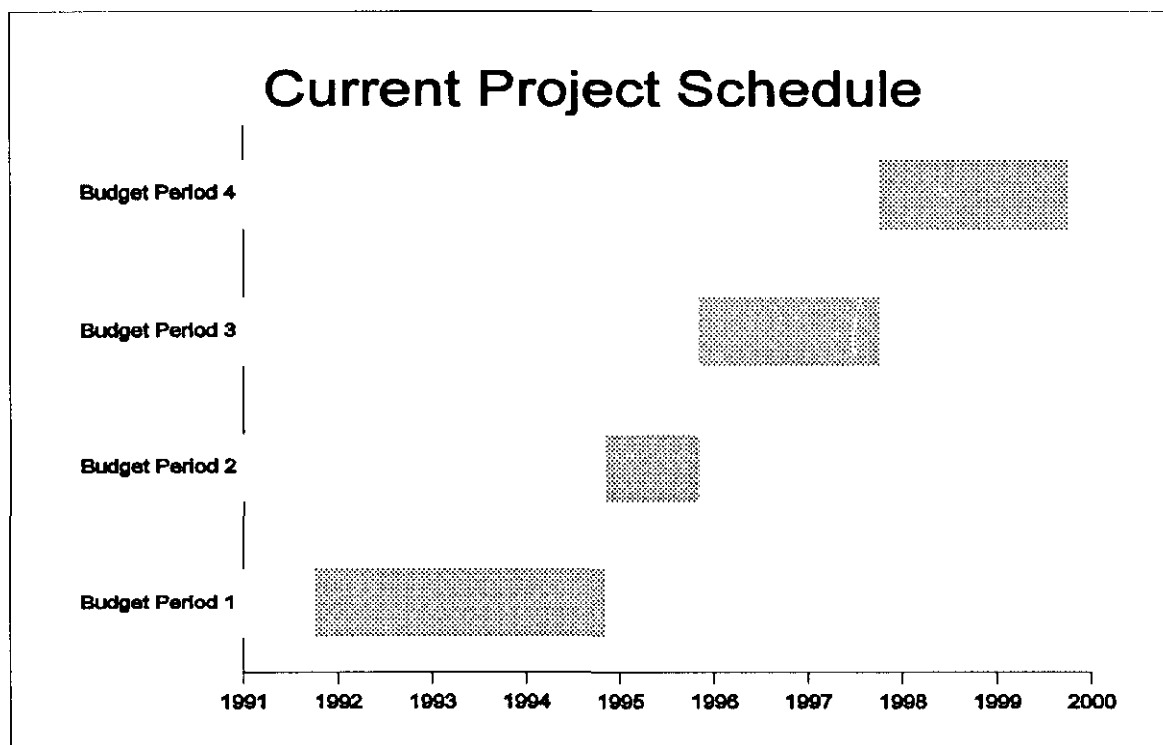


Figure 2- Project Schedule

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3. "Topical Report for the Des Moines Energy Center 80MW PCFB Repowering Project", Cooperative Agreement No. DE-FC21-91MC27364.
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**AMERICAN ELECTRIC POWER
PRESSURIZED FLUIDIZED BED COMBINED CYCLE
TECHNOLOGY STATUS**

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ABSTRACT

The Ohio Power Company's Tidd Pressurized Fluidized Bed Combined Cycle (PFBC) program continues to be the only operating PFBC demonstration program in the nation. The 70 MWe Tidd Demonstration Plant is a Round 1 Clean Coal Technology Project constructed to demonstrate the viability of PFBC combined cycle technology. The addition of a hot gas cleanup bypass stream at Tidd, separately funded by the USDOE as an R&D project is intended to demonstrate that advanced particle filters (APF) can operate reliably in a PFBC environment. The plant is now in its fourth year of operation. All objectives established for the original three year test program have been achieved. The technology has clearly demonstrated its ability to achieve sulfur capture of greater than 95%. The calcium to sulfur molar ratios have been demonstrated to exceed original projections, thereby enhancing the economic viability of the process. Unit availability has steadily increased and has been demonstrated to be competitive with competing technologies. The operating experience of the first forty months of testing has moved the PFBC process from a "promising technology" to a viable, proven option for efficient, environmentally acceptable base load generation. This paper reviews the operating history of Tidd, and presents the findings of the most recent series of tests.

INTRODUCTION

The Tidd PFBC Demonstration Plant, a 70 MWe electric generating station, located in Brilliant, Ohio, is the first pressurized fluidized bed combined cycle plant to operate in the United States. Funding for the \$210 million program is provided by Ohio Power Company, The U.S. Department of Energy, The Ohio Coal Development Office, and the PFBC process vendors - Asea Brown Boveri Carbon (ABBC) and Babcock And Wilcox (B&W).

The Project involves the repowering of a 1940's vintage pulverized coal plant with PFBC components. Engineering and Design was provided by American Electric Power Service Corporation. Technology related systems and equipment were provided by Asea Babcock (AB), A partnership of ABBC and B&W. New construction and modification to existing systems were carried on by Ohio Power Company.

PLANT DESCRIPTION

The original Tidd plant consisted of two 110 MWe steam turbine generators supplied with steam by conventional coal fired boilers. The unit 1 steam turbine was repowered at approximately 50% capacity by the addition of a PFBC combustor steam generator and a gas turbine exhaust economizer. Other additions included in the AB scope of supply were the gas turbine and GT generator, the coal preparation system, the coal and sorbent feed systems, the gas cleaning system, and the cyclone and bed ash removal systems. The major balance of plant improvements included the addition of an electrostatic precipitator, combustor building, bed ash and cyclone ash silos, and sorbent preparation facilities. Modification of the coal and sorbent storage areas and a revamped control room completed the needed improvements for the conversion. The remainder of the balance of plant utilized the original Tidd balance of plant components and systems.

The PFBC Power Island (Figure 1), which was incorporated into the existing plant, was designed to provide 440,000 pounds per hour of steam flow at 1300 psia and 925°F. Plant generation output was expected to be 72.5 MWe gross (57.1 MWe from the steam turbine generator and 15.4 MWe from the gas turbine generator).

Air, at approximately 175 psia, is provided to the combustor by the gas turbine compressor through the outer annulus of a coaxial air/gas pipe. Inside the combustor vessel, the air is ducted into the boiler where it fluidizes the bed materials and provides oxygen for combustion. The bed design temperature is 1580°F, which was established by the maximum acceptable gas turbine inlet temperature. This temperature is well above the minimum coal combustion temperature and provides sufficient margin to preclude melting of the coal ash constituents. In addition this temperature is conducive to a relatively high reaction rate for SO₂ capture by direct sulfation of the calcium carbonate in the sorbent,

while being well below the temperature at which alkalis vaporize and present a corrosion problem for the gas turbine. Formation of thermal NO_x is essentially nil due to the low combustion temperature and much of the NO_x formed from nitrogen in the coal is reduced to N₂ and O₂ at char sites in the bed.

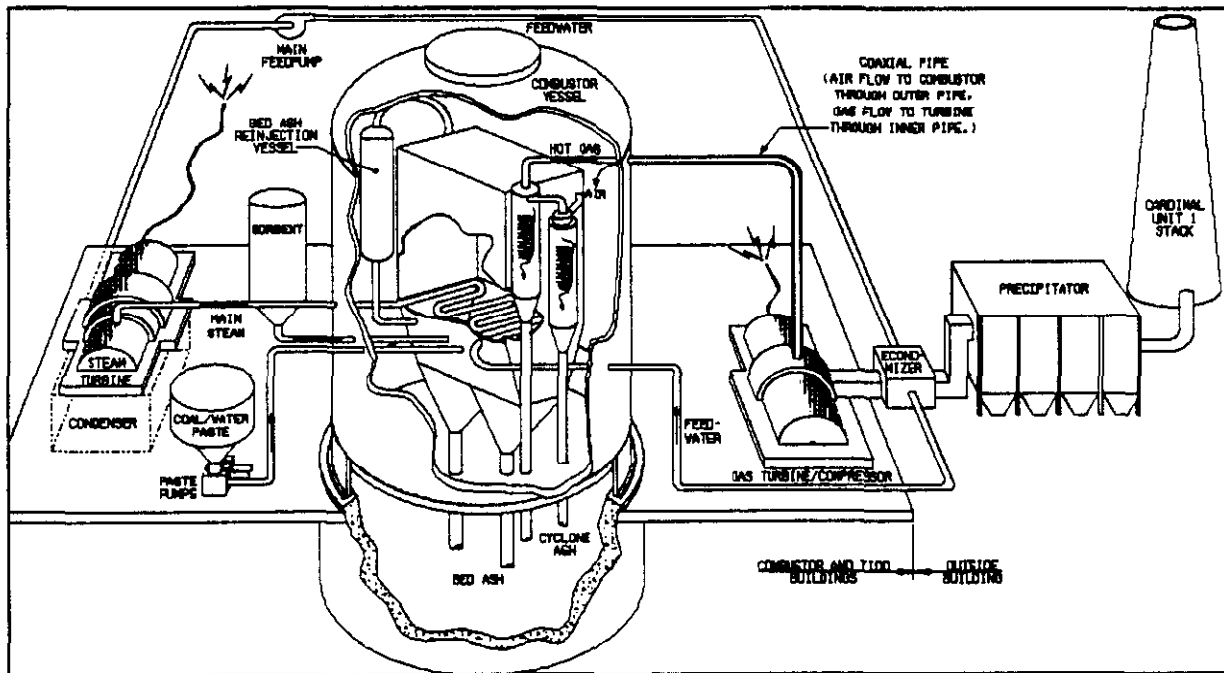


FIGURE 1 - TIDD PFBC ISLAND

Seven parallel strings of gas cleaning cyclones remove 99% of the ash elutriated by the gas leaving the bed. Six of the strings consist of a primary and a secondary cyclone, the seventh is comprised of a primary cyclone in series with an experimental ceramic Advanced Particle Filter (APF). All of the cyclones are located in the combustor vessel. The APF is located outside the combustor in a separate pressure vessel. The gas from all seven strings is combined inside the pressure vessel and routed to the gas turbine via the coaxial air/gas pipe. The gases are expanded through an ABB Stal GT-35P gas turbine, which produces shaft power to run the gas turbine compressor (approximately 2/3 of the power at full load) and to drive the gas turbine generator (remaining 1/3 of the power). The turbine exhaust gases then pass through the economizer where excess heat is transferred to the feedwater and then through the electrostatic precipitator for further particulate collection. The gases then are ducted to Cardinal Unit No. 1 where they are combined with that unit's exhaust stream and exit to atmosphere via the Cardinal stack.

The steam cycle is a Rankine cycle with a subcritical once-through boiler. Condensate is heated by three stages of low pressure heaters and a gas turbine intercooler as it is pumped to the deaerator. A single high pressure heater and the turbine exhaust gas economizer raised the final feedwater temperature to approximately 480°F. The feedwater then passes through the boiler bottom hopper and furnace wall enclosures where additional subcooled preheating occurs. The feedwater then enters the in-bed evaporator tubes where the steam is generated and attains a slight degree of superheat. The steam then passes through the in-bed primary superheater, is attemperated and attains final steam temperature in the in-bed secondary superheater. At steam flows below 40% capacity, a circulation pump maintains sufficient flow rate through the evaporator circuits for cooling protection. The resultant moisture in the evaporator outlet steam is separated by centrifugal action in a vertical separator.

Coal is injected into the fluidized bed as a paste nominally containing 25 percent water by weight. Raw coal of 3/4 inch top size is fed to a double roll crusher which reduces the material to minus 1/4 inch. The crushed coal is conveyed to a screen to collect oversized material then to a mixer where water is added to make the paste. A recycle line, which is located upstream of the screen, returns a portion of the material to the crusher. Recycle is regulated to attain a sufficient quantity of coal fines, which are necessary to make a cohesive and pumpable coal paste. The paste is fed from the mixer into two interconnected surge tanks which supply six hydraulically driven piston pumps. These pumps feed the paste to individual fuel nozzles which deliver the paste into the fluidized bed just below the tube bundle.

The sorbent, which is generally dolomite, is crushed to minus 1/8 inch size and dried in a hot air swept hammermill crusher. This material is then injected into the fluidized bed via alternating dual lockhoppers that feed a dilute phase pneumatic transport system. The original transport system design split the flow into two feed nozzles; however, the system has recently been modified to provide a total of four feed nozzles.

Material is drained from the bed to maintain the bed level. This "bed ash" accounts for approximately 40% of the total ash and is generally 99% larger than 60 mesh (250 microns). The ash is drained in a controlled manner by gravity via two parallel lockhoppers. Material elutriated from the bed and collected in the cyclones, approximately 60% of the ash, is generally 99% smaller than 60 mesh. This "cyclone ash" is removed by means of a pneumatic transport system which depressurizes and cools it.

OPERATIONAL OVERVIEW

The operating experience from the Tidd PFBC facility has been one of gradual and constant improvement starting with the initial combined cycle operation in November, 1990. Evidence of this is presented graphically in Figure 2, which

depicts monthly operating hours for the period from 1991 through June 1994.

During the period from November 1990 through September 1991, the unit fired coal for a total of 818 hours, with the longest continuous run being 110 hours.

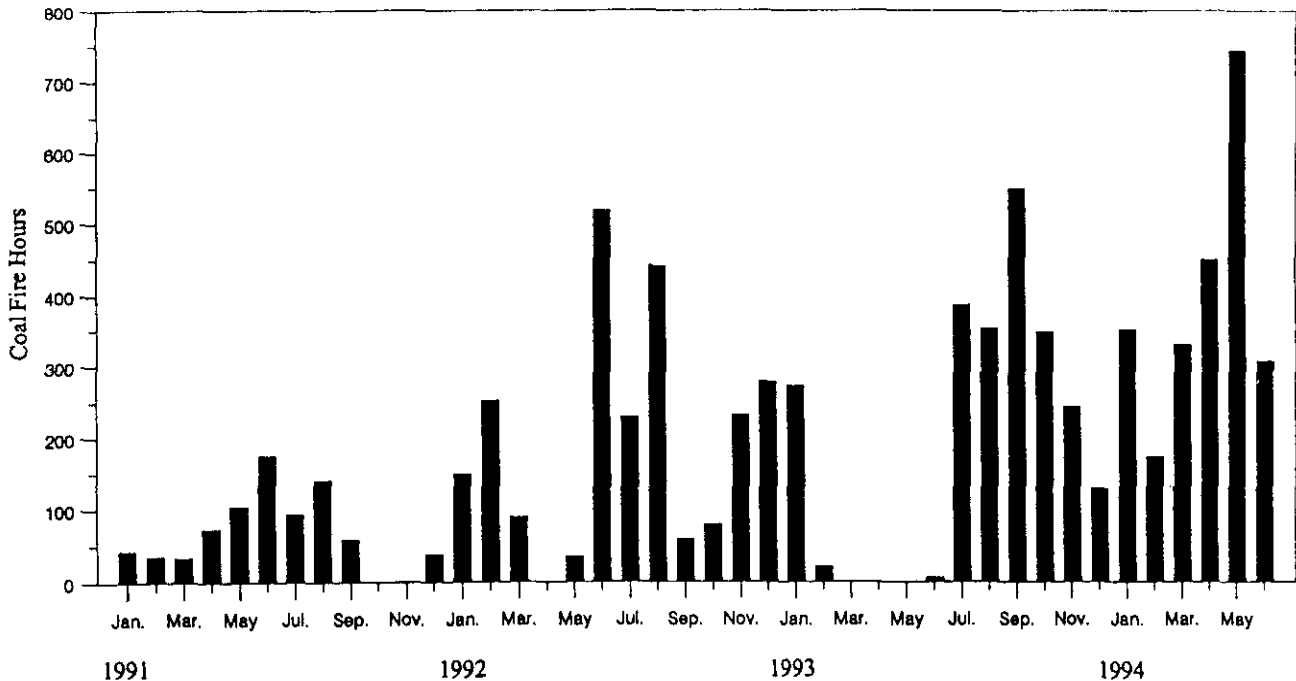


FIGURE 2 - MONTHLY COAL FIRE HOURS

During that period, the unit was plagued with numerous problems, the most significant being cyclone ash removal system plugs, fires at the cyclone gas inlets and in the ash dip legs, coal feed system plugs, economizer fouling, and boiler vertical separator level control problems. In addition, boiler in-bed tube surface was found to be insufficient and the air distribution sparge ducts were experiencing excessive distortion. During this period a number of minor design revisions were incorporated that led to improved unit operability; however, a twelve week outage was scheduled in the Fall of 1991 in order to correct the major unit deficiencies. The key modifications performed during the outage include:

- o Added surface to the boiler in-bed tube bundle in order to increase the heat absorption and steaming capacity.
- o Replaced the expansion joints in the air distribution sparge ducts with a revised design.
- o Revised the cyclone ash removal system.
- o Installed sootblowers and anti-vibration ties in the economizer.

The unit was returned to service in early December, 1991. After a series of short runs, the unit began to operate more reliably; however, run durations were still limited by operating problems. From mid-December through early March, 1992, the unit fired coal for a total of 530 hours with the longest run being 154 hours. At that point, cracks were discovered in the root area of a number of the gas turbine low pressure turbine blades. A nine week outage was taken in order to replace the blades and to commission the APF piping system.

The unit was returned to service in late May, 1992. The first run was very short due to corrosion problems on the expansion joints in the APF piping. Since that problem necessitated a major modification, the unit was returned to service with the APF system blocked off and only six gas cleaning strings in service. After a two week outage, the unit was returned to service and was run continuously for thirty one days with a capacity factor of nearly 70%. The unit was kept on-line in spite of a plugged secondary cyclone ash removal line experienced early in the run, since it was determined that this would not dramatically increase gas turbine erosion. At the end of the thirty-one days, the unit was removed from service in a controlled manner in order to perform equipment inspections. The unit acceptance tests were also completed during this period.

From July 1992 through February 1993, unit operation was reasonably reliable permitting a number of performance tests to be conducted. The most significant problems during this period were fuel nozzle plugs induced by coal paste preparation problems and occasional primary cyclone system plugs. The unit was operated periodically with plugged secondary cyclone ash removal lines. Other factors contributing to unit down time were attempted operation with a magnesian limestone as the sorbent, which caused two unit trips due to excessive bed sintering and operational problems with the APF system which was connected in service from late October through early December. In addition, the air distribution sparge ducts continued to distort and began to experience localized cracking. In early February, 1993, the gas turbine threw two low pressure turbine blades, which resulted in extensive damage to the machine. As a result, the unit experienced a twenty-week outage to affect repairs. During this time the secondary cyclone ash removal system was completely reconfigured and the air distribution sparge ducts were replaced.

The unit was returned to service in late June, 1993. From that time through the end of February, 1994, the unit operated more reliably and fired coal for a total of 2015 hours with three runs in excess of 400 hours. The improved unit reliability permitted a large number of unit performance tests to be conducted, which established a broad base of test data. During this period, the performance of the secondary cyclone ash removal system was greatly improved. However, plugging of primary cyclone ash removal lines at unit start-ups became a nuisance causing four unit outages. This problem was attributed to continued degradation of the gaskets and leakage into the system which reduced its ash carrying capacity. In

addition to the key system and component problems enumerated, the unit periodically experienced other nuisance trips. These included boiler sensing line fitting leaks inside the combustor, control logic problems, local component controller failures and other minor problems. These events collectively had a significant impact on unit down time, particularly since the systems necessary for combustor cooldown, access and restart were not optimized for the rapid return of the unit to service.

Another factor impacting unit availability was the lack of redundancy in key systems in this demonstration plant. In order to minimize the cost of the facility, the usual redundancy that would be incorporated into a commercial plant was left out. This factor alone had major impacts, particularly in regard to the coal preparation and injection systems. Finally, one other issue must be recognized when viewing the Tidd operating history. Operation and testing at the Tidd facility has not been done in a manner solely to maximize operating time. Throughout the course of the three-year test program, deliberate operating challenges have been undertaken in the interest of determining the unit flexibility and operating limits and improving unit performance. Despite all of these considerations, the unit fired coal for over 6050 hours during its initial three year run.

The fourth year of unit operation, which began on March 1, has proven to be significant in demonstrating both unit reliability and in improving process performance. Starting on March 1, 1994 through the end of June, 1994, the unit logged approximately 1800 hours on coal. Unit availability during this period was approximately 63% and the longest continuous run (1070 hours) was recorded. The steps taken to improve reliability coupled with changes in bed operating parameters are becoming evident. There is little doubt that a unit designed for commercial operation can achieve availability factors consistent with the expectations for central generating units.

BED PROCESS FINDINGS

Post-Bed Combustion

Initial operation of the unit at intermediate and high loads revealed that combustion was occurring beyond the bed resulting in excessively high temperatures of the gas in selective cyclone strings and of the ash in the primary cyclone dip legs. The dip leg combustion was attributed to excessive unburned carbon carryover; whereas, the gas stream combustion was attributed to carryover of unburned volatiles. It was determined that both of these phenomena were due to high localized fuel release combined with rapid fuel breakup and devolatilization. Insufficient oxygen in these localized regions resulted in plumes of low O_2 gas with unburned volatiles and fine char at each of the six fuel nozzle discharge points. This was documented through oxygen measurements taken in the freeboard above the fuel nozzle discharge points. This problem was gradually minimized through improved fuel splitting, installation of a steam induced freeboard gas mixing system, and

improvements in the coal paste quality. The latter factor proved to have the greatest impact on reducing the degree of post bed combustion.

During recent runs, the unit has operated for extended periods with no signs of post bed combustion. However, upsets in coal paste preparation, such as excessive water addition, still result in upward swings in freeboard gas temperature. Such swings pose a potential trip risk at full bed height due to excessive gas turbine temperatures. At lower bed heights, these swings are not a problem, since the freeboard temperature runs well below the bed temperature due to the convective cooling action of the tubes above the top of the bed. The post bed combustion phenomenon is understood to the extent that operations personnel are able to monitor plant conditions and take early action to prevent or mitigate such occurrences.

Sinter Formation

The formation of small quantities of hollow egg shaped agglomerates, in the range of 1 - 2 inches in size (Sintering), has been observed throughout the operation of the unit. However, these did not pose a major operating problem at low bed levels, since the formation rate was slow and sinters drained from the bed at a rate which prevented any significant buildup. In late 1993 and early 1994, sintering became a significant operating problem. The rate of sinter formation increased greatly when the unit was operated at higher bed levels. At these higher formation rates, sinters accumulated in the bed causing bed conditions to deteriorate. Uneven bed temperatures, decaying bed density, and a reduction in heat absorption were common symptoms of bed sintering.

Initial speculation of the cause of high load sintering focused on the issues of higher local heat release associated with higher unit loads and insufficient fuel splitting. Modifications were made to the fuel nozzles as well as to fuel distribution baffles in an attempt to mitigate these concerns. No significant reduction in sintering was observed. The hypothesis that poor bed mixing and less than ideal fluidization were key contributors was subsequently developed. A series of performance tests were proposed to demonstrate that better mixing would significantly reduce sintering. Improvements in fluidization were achieved by reducing the size consist of the dolomite feed, thereby reducing bed size consist, while maintaining fluidizing velocity constant. The introduction of finely crushed dolomite (-12 mesh) versus the normal coarse crush (-6 mesh) significantly reduced sintering to the extent that full bed temperature of 1580°F could be maintained with no evidence of sintering.

The most severe incidents of sintering all occurred when feeding limestone. It is postulated that sintering of a limestone bed may have causes beyond those identified in the sintering of a dolomite bed. The reduced amount of MgO in the limestone may contribute to the uncontrolled sintering which resulted when feeding this material. A detailed chemical investigation into the mechanism involved in this

sintering revealed that the likely cause is calcium from the sorbent fluxing the potassium-alumina-silicate clays in the coal ash. The nuclei of the sinters appear to be coal paste lumps which become sticky and collect bed ash on their surface. The coal then burns away, leaving the coal ash to react with the bed material. The less aggressive sintering with dolomite is explained by the fact that increased quantities of MgO tend to raise the melting temperatures of CaO-MgO-Al₂O₃ mixtures. In evaluating the sintering problem, it must be recognized that the extremely low ash fusion temperature of the Pittsburgh No. 8 coal burned at Tidd is likely a major contributing factor to sintering. Testing with finer crush limestone is expected to be conducted in the near future. It is expected that the better mixed bed will permit the use of limestone.

UNIT PERFORMANCE

Testing has progressed significantly since completion of the first three years of operation. The improved unit availability has provided the opportunity to conduct a greater number of varied performance tests than was previously possible. The most recent series of tests, were devised to address sintering issues by reducing the size consist of the bed. The finer sorbents, which were specified and purchased with a narrow size consist range, proved to be successful in addressing sintering while at the same time demonstrating exceptional improvement in the Ca/S molar ratios. Recent test results for the unit operating on Pittsburgh #8 coal and National Lime Carey or Plum Run Greenfield Dolomites are presented in table 1.

SORBENT TYPE	NATIONAL LIME CAREY DOLOMITE			PLUM RUN GREENFIELD DOLOMITE			
	55	57	58	52	60	61	
TEST NUMBER	55	57	58	52	60	61	DESIGN
TEST DATE	5/12/94	5/18/94	6/1/94	5/2/94	6/9/94	6/10/94	NA
BED LEVEL (INCHES)	115	115	113	114	107	115	126
MEAN BED TEMP. (F)	1580	1575	1575	1500	1576	1500	1580
FIRING RATE (MWt)	182.1	173.1	186.9	163.6	175.2	167.3	204.4
UNIT OUTPUT (MWe)	56.9	53.1	56.6	48.8	52.2	48.2	72.5
COAL SULFUR (LB SO ₂ /MMBTU)	5.01	5.63	5.32	5.44	5.24	4.99	5.5
SULFUR RETENTION (%)	90	90	90	90	90	90	90
Ca/S MOLAR RATIO *	1.84	2.2	1.46	1.91	1.32	1.2	1.64
NO _x EMISSIONS (LB/MMBTU)	0.2	0.2	0.2	0.23	0.22	0.29	0.3
SORB. SIZE CONSIST (MESH)	-12	-6	-20	-6	-12	-12	-6
*Ca/S is normalized to 1580 F							

TABLE 1 - TIDD PERFORMANCE TEST RESULTS

The above data clearly shows a significant improvement in sulfur capture resulting from the injection of finer dolomitic material as a the sorbent. The improvement in performance is significantly greater than can be explained solely by the larger sorbent exposed area due to the finer material. The noted improvement in performance must also be the result of significant improvements in bed fluidization and mixing. Especially when a number of other recorded system parameters such as steam generation and bed/evaporator temperature profiles also point to enhanced bed dynamics.

Recent performance testing has been limited to approximately 115 inches due to summer limitations on the gas turbine. However, previous testing has provided a sufficient basis to confirm the correlations, previously developed at Grimethorpe, thereby permitting extrapolation of the data to varied temperatures, bed heights, and sulfur captures. Figures 3 and 4 show sorbent utilization (Ca/S) versus bed height for 90 and 95 percent sulfur capture.

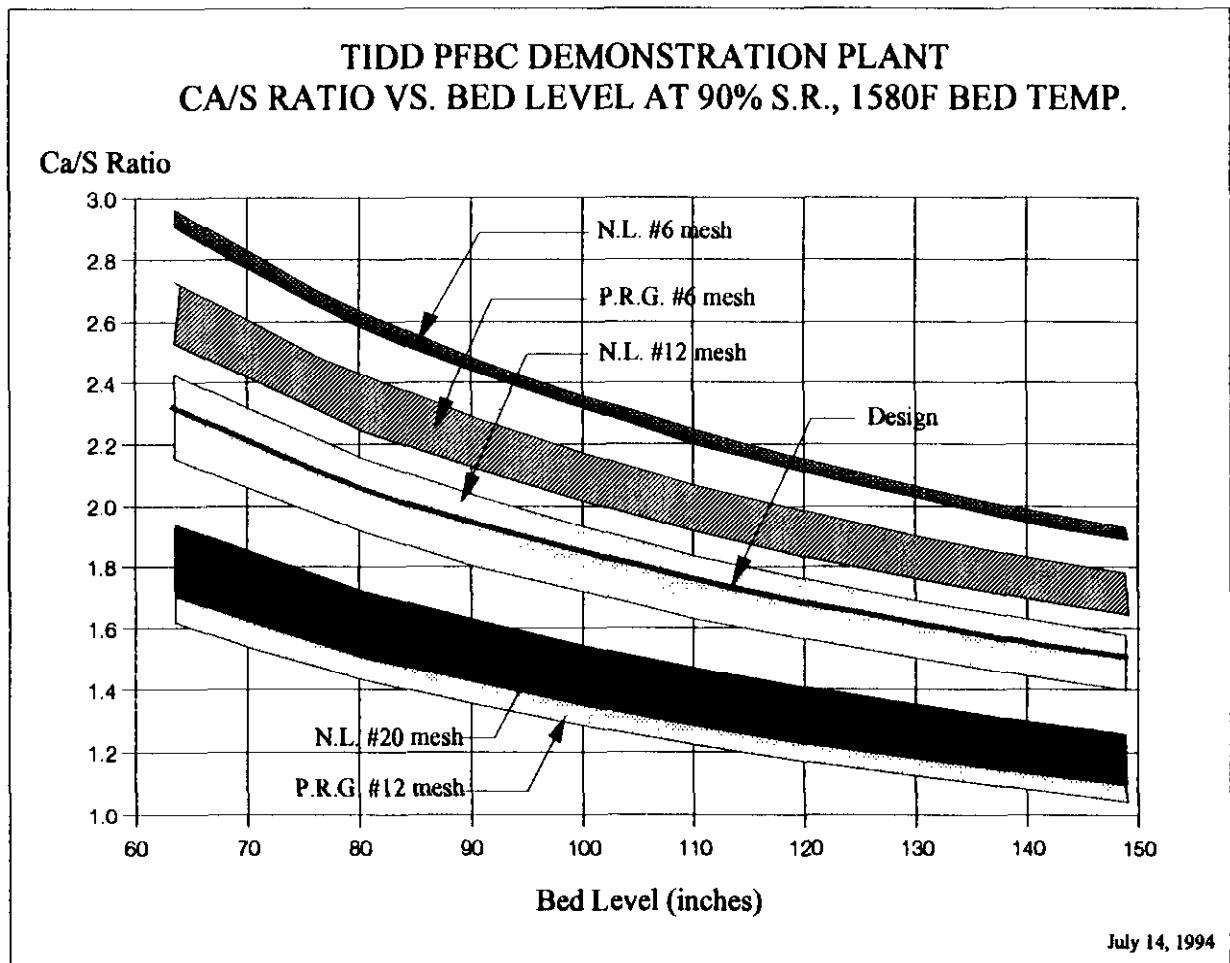


FIGURE 4 - BED HEIGHT VS Ca/S RATIO, 90% SULFUR CAPTURE

The affect of sorbent feed size consist on sorbent utilization is clearly seen. Reducing sorbent size consist from coarse sorbent (-6 mesh) to finer sorbent (-12 to -20 mesh) results in significant increases in sorbent sulfation and therefore reduced sorbent feeds to achieve a predetermined level of sulfur capture. In addition to sorbent size consist effect on sorbent utilization, figures 4 and 5 show the impact of sorbent reactivity. National Lime Carey dolomite (NL) has generally been demonstrated to be less reactive than the Plum Run Greenfield dolomite (PRG).

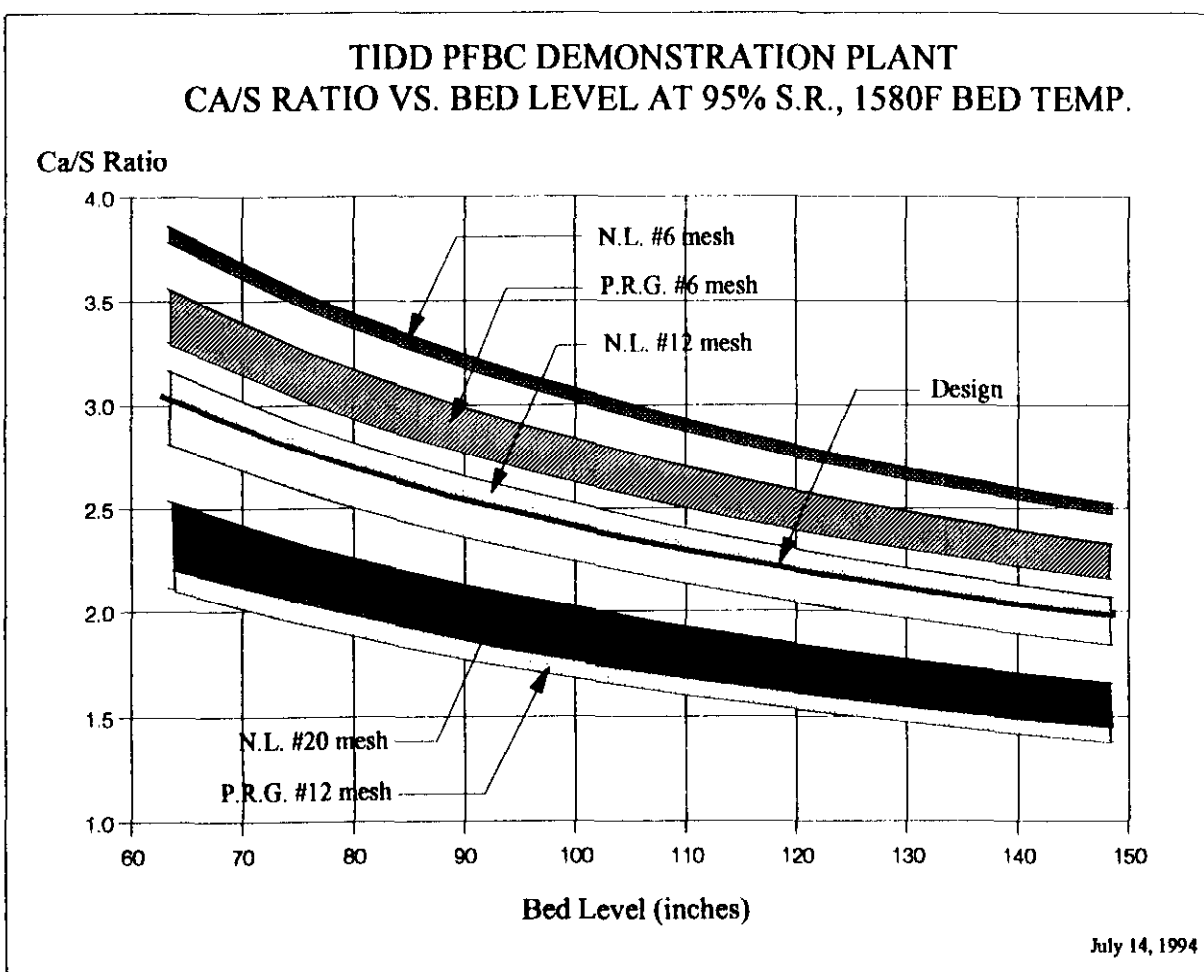


FIGURE 5 - BED HEIGHT VS Ca/S RATIO, 95% SULFUR CAPTURE

FOURTH YEAR TESTING

Preliminary findings in the first three years of operation indicated that finer sorbents and variation in sorbent feed methods affected both bed dynamics and sorbent utilization. Testing in the fourth year has confirmed these observations. The introduction of significantly finer sorbent has had significant positive impact.

Optimization of sorbent feed size consist is expected to continue over the next several months. A series of tests aimed at establishing the optimum sorbent size range for maximum sorbent utilization is planned. The affects of sorbent feed method (dry vs wet) will be further evaluated. Early testing has suggested that the addition of superfine (-325 mesh) sorbent to the coal paste improves sorbent utilization. A series of tests aimed at quantifying the impact of in bed oxygen level on sulfur capture and sorbent utilization is also planned. Finally, testing with magnesian limestone is planned to demonstrate the ability of PFBC to use this material without excessive sintering.

Data obtained during testing of the Tidd APF slipstream clearly indicate that significant sulfur capture is occurring across the filter, testing on the APF is expected to continue to quantify sulfur capture across the ceramic filter elements, while addressing the issue of ceramic filter longevity in a combustion gas environment.

Equipment evaluation aimed at defining service life is expected to continue. Gas turbine inspections are planned on a regular basis as are inspections of the in bed tube bundle.

CONCLUSION

The Tidd PFBC Demonstration Plant has now achieved over 7880 hours of coal fired operation. Approximately 1800 hours, including the longest continuous run of 1070 hours, were achieved during the last four months of operation. Unit availability during this period was approximately 63%.

A total of 62 performance tests have been conducted to date. Eleven tests were completed during the latest run. Test objectives during the last run were aimed at reducing bed sintering and improving sorbent utilization. The tests were conducted using -12 to -20 mesh sorbent. The finer sorbent was expected to improve bed mixing and fluidization, Thereby mitigating sintering and improving sorbent utilization. Bed conditions improved significantly and operation at 1580°F bed temperature was achieved with little, if any, bed sintering. Performance testing was completed at 1580°F, 115 inch bed level and 90% sulfur capture. The results showed a marked improvement in sorbent utilization, Ca/ S molar ratios around 1.3 were indicated. This data extrapolates to Ca/ S molar ratios, at full bed heights, of 1.1 and 1.5 for 90% and 95% sulfur capture.

In addition to improved sorbent utilization, the unit demonstrated better heat transfer than had previously been achieved as well as a more homogeneous bed temperature distribution.

The reliability of PFBC has, and continues, to be demonstrated. The process, which was initially demonstrated in early operation, has been refined and optimized to the point where PFBC is competitive with all other technologies for both low and high

sulfur coals. Expected enhancements of both systems and process are expected to further improve sorbent utilization and system performance beyond the levels already achieved while continuing to demonstrate the service life of both the gas turbine and the boiler tube bundle. The process has been demonstrated to be environmentally sound, cost effective, and capable of achieving the reliability and availability required in a power generating unit. Commercial deployment remains the only hurdle left to PFBC technology.

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**FOUR RIVERS ENERGY MODERNIZATION PROJECT
ADVANCED PRESSURIZED CIRCULATING FLUIDIZED BED
COMBUSTION PROCESS
PROJECT OVERVIEW AND STATUS**

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ABSTRACT

Air Products was selected in Round 5 of the DOE Clean Coal Technology program to build, own, and operate the first commercial power plant using advanced Pressurized Circulating Fluidized Bed (PCFB) combustion technology. The Four Rivers Energy Modernization Project (Four Rivers) will produce approximately 70 megawatts electricity (MWe) electricity, and will produce up to 400,000 lb/hr steam, or an equivalent gross capacity of 95 MWe. A limited partnership, Four Rivers Energy Partners (FREP), has been formed to be the co-participant with DOE in executing the Four Rivers Project.

INTRODUCTION

The advanced PCFB combustion process has been in active development for the past six years. An initial DOE-sponsored study by Foster Wheeler identified significant economic and environmental advantages [1] for the process. Recent pilot testing by Foster Wheeler and Westinghouse (WEC) has focused on the development of the process critical components [2].

These tests provided the design basis for a 3 megawatt thermal (MWth) integrated pilot plant to be operational at Foster Wheeler's Livingston facility in late 1994, and for the 7 MWe (equivalent capacity) Wilsonville Power Systems Development Facility [3]. Independently, LLB Lurgi Lentjes Babcock Energietechnik (LLB) has run a 15 MWth PCFB combustor with hot gas filtration for several years [4]. These development efforts led Air Products to join with Foster Wheeler, LLB and WEC to successfully propose the Four Rivers Project at Air Products' chemicals manufacturing facility in Calvert City, Kentucky under Round 5 of the Clean Coal Technology Program.

Efficient, environmentally acceptable, and economic processes such as the advanced PCFB combustion process will help to ensure that coal continues to play a major role in power generation. A recent DOE study compared efficiencies of today's advanced PCFB process against a conventional pulverized coal (PC) boiler with a scrubber, first generation PCFB, and Integrated Gasification Combined Cycle (IGCC) [5]. The results, summarized in Table 1, show a significant advantage for the advanced PCFB process.

Advanced PCFB	PC w/ scrubber	1st Gen. PCFB	IGCC
43.7	36.6	40.8	42.3

Table 1. Net Plant Higher Heating Value (HHV) Efficiency [5]

Within the next 8-10 years, advanced PCFB power cycles will be able to achieve 45% (HHV) thermal efficiency, and beyond year 2000, cycles are anticipated to achieve 50% [6]. The high efficiency is derived from a combined cycle operation in which approximately 45% of the electric power is generated in the gas turbine, with the balance from the steam cycle. The inherent higher plant efficiency provides a number of environmental advantages. For example, coal consumption is 25% lower per unit power output than a pulverized coal or Atmospheric Circulating Pulverized Bed (ACFB) plant. Consequently, there will be lower emissions of Carbon Dioxide (CO₂) and other pollutants. In addition, 95% sulfur capture can be attained with a Calcium to Sulfur (Ca/S) molar ratio less than 2.0. This exceeds the 90-93% sulfur removal criterion in the Prevention of Significant Deterioration (PSD) air permitting regulations with Best Available Control Technology (BACT) review. The projected Sulfur Oxides (SO_x) emissions rate of 0.3 lb/MMBtu is significantly lower than the 1990 Clean Air Act Amendments Title IV Acid Rain limits for the year 2000 (1.2 lb/MMBtu). Nitrogen Oxides (NO_x) emissions are estimated at 0.3 lb/MMBtu, which are half those required by New Source Performance Standards (NSPS). In LLB's pilot plant tests, particulate emissions have consistently measured below 3 ppm (0.003 lb/MMBtu), which is an order of magnitude lower than NSPS.

This excellent environmental performance comes with a competitive price. The advanced PCFB process, as fully commercialized, will have a life cycle cost-of-electricity 20% below the cost of conventional coal technologies [1]. The savings are due to higher thermal efficiency; lower capital, operating, and maintenance costs; and shorter construction times.

As an independent power producer, Air Products considers the PCFB technology to be strategic for its cogeneration business. We recognize its advantages for repowering, and feel it will play an important role at the turn of the century for power generation. This paper will introduce the advanced PCFB process for the Four Rivers Project, discuss the critical technology components, provide an update on the current status of the project, review the project team scope, and present the project schedule.

PROCESS DESCRIPTION

The Four Rivers Project is a cogeneration facility, producing approximately 70 MWe to the grid and 310,000 lb/hr of 190 psia/420°F process steam to Air Products' adjacent chemicals manufacturing facility. The gas and steam turbines generate approximately 40 MWe and 30 MWe, respectively. At its annual average operating condition, the feed rates are 36.5 ton/hr western Kentucky high-sulfur bituminous coal and 7.5 ton/hr local limestone. The steam load will vary from 250,000 lb/hr in summer to 400,000 lb/hr in winter. If all of the steam were expanded through the steam turbine, the plant would generate about 95 MWe gross.

In the advanced PCFB process, air is withdrawn from the gas turbine's compressor for the carbonizer and PCFB combustor. In the carbonizer, an air-blown pressurized fluidized bed gasifier, the coal slurry undergoes partial combustion to produce a low-Btu fuel gas and char. Limestone is added to capture sulfur and enhance gasification reactions. Solids are removed from the fuel gas in a cyclone and ceramic filter. Trace alkali components are removed in a packed bed adsorber. Char from the carbonizer, additional coal slurry, and limestone are burned in the PCFB combustor. The PCFB combustor generates steam in its waterwalls and an INTREX™ integrated heat exchanger. Flue gas from the PCFB combustor is also cleaned by a cyclone, ceramic filter, and alkali removal train.

The fuel gas from the carbonizer is burned with cleaned, hot, pressurized air from the PCFB combustor in the external topping combustor. This stream is expanded in the gas turbine to drive a generator and the turbine's air compressor. The turbine exhaust raises additional steam in

the Heat Recovery Steam Generator (HRSG). Steam raised in the PCFB combustor and HRSG drives the steam turbine generator.

CRITICAL TECHNOLOGY COMPONENTS

The following is a description of the critical technology components, which are the key elements of the second generation PCFB process. Demonstration of these components at the commercial scale is a primary goal for the Four Rivers Project.

Carbonizer

The distinguishing feature between the first generation PCFB process and the advanced PCFB process is a fired gas turbine. Increasing the gas turbine inlet temperature is the key to higher efficiency. The carbonizer generates the fuel gas which is fired in the topping combustor to increase the gas turbine inlet temperature.

The carbonizer is a vertical, pressurized spouted bed reactor which is refractory-lined. It is approximately 46 feet high and has a conical bottom. The lower 25 feet of the carbonizer has an 8-foot inner diameter, while the upper 21 feet of the vessel expands to 10.5-foot inner diameter.

Coal slurry is fed through radial nozzles and sorbent is gravity fed with nitrogen assist to the lower zone of the vessel. The carbonizer operates at 250 psia/1700°F to produce 135,000 lb/hr of approximately 120 Btu/scf fuel gas. Limestone captures sulfur as Calcium Sulfide (CaS) and catalyzes cracking of oil and tar species which could foul the ceramic filter. Fuel gas, with entrained char and sorbent, exits at the top of the vessel. A cyclone and ceramic filter removes the particulate, which is combined with bed drains in the char transfer hopper. The particulates and the char are fed to the PCFB combustor through an "N" valve.

PCFB Combustor

The PCFB combustor provides 460,000 lb/hr of 1515 psia/950°F steam. In addition, it heats over 800,000 lb/hr of vitiated air to 1600°F for the topping combustor. Finally, it consumes char from the carbonizer, and converts CaS to innocuous Calcium Sulfate (CaSO₄).

The PCFB combustor is comprised of a membrane wall combustion chamber, cyclone, "J" valve, INTREX™ integrated heat exchanger, and ash stripper/coolers, which are all housed in a 110-

feet high x 28-feet diameter pressure vessel. It operates at 225 psia/1600°F with varying amounts of excess air, depending on the export steam load.

The combustor has a very small footprint because PCFB combustion generates a very intensive heat output per unit cross-section area. The steam-cooled cyclone has a 2-inch layer of refractory, which facilitates rapid start-up, and reduces weight and structural support requirements. The INTREX™ integrated heat exchanger has three bubbling fluidized bed cells in which solids are distributed through serpentine superheat or steam generating coils.

Air enters through the bottom head of the pressure vessel to pressurize the vessel. Primary air flows through an annular opening in the pressure vessel and into the externally mounted startup burner. From the burner it flows into the bottom of the water-cooled air plenum. It then passes through a water-cooled air distributor which has directional air nozzles. Secondary air is injected into the furnace through multiple openings in the front wall at two elevations. A portion of the secondary air is pre-heated in the ash stripper-coolers. The staged combustion minimizes NO_x formation.

Carbonizer char is discharged from the "N" valve into the lower combustor through an opening on the centerline of the combustor front wall. Coal slurry is injected into the lower combustor through two air-atomized nozzles positioned on either side of the char feed opening. Sorbent is gravity fed with air assist through two openings in the front wall near the fuel feed points. Ash is removed through two 100% stripper-coolers located on the side walls of the combustor. The coolers have two sections divided by a refractory brick wall. Ash is cooled to 500°F and discharged through a rotary valve.

High Temperature Gas Cleaning Systems (HTGC)

The HTGC is essential for operating the advanced PCFB technology. As discussed above, the difference between the first generation and the advanced PCFB processes is the fired gas turbine, which raises the turbine inlet temperature from 1600°F to 1975°F for Four Rivers and as high as 2350°F for future facilities. These high temperatures require that almost all particulate and trace species such as alkalis be removed to prevent erosion, corrosion, and formation of deposits in the topping combustor or gas turbine.

Separate HTGC trains are used for the carbonizer fuel gas and PCFB combustor vitiated air. Each HTGC consists of three cleaning stages in series: a cyclone separator, a ceramic filter, and

a fixed-bed alkali removal unit. The carbonizer has a stand-alone cyclone of conventional design. The PCFB cyclone is integral to the PCFB combustor and is located within the pressure vessel.

Carbonizer Candle Filter

Westinghouse will provide two 100% ceramic filter assemblies for the carbonizer fuel gas. The carbonizer train cleans 135,400 lb/hr of 230 psia/1400°F fuel gas containing char and sorbent. The ceramic filter is a 44-feet high x 10-feet diameter refractory-lined pressure vessel containing the gas inlet shroud, tubesheet, three vertical filter clusters, and a bottom conical section which acts as a dust hopper.

The system is designed to handle particulate loading from 2,000 to 30,000 ppmw and a ratio of char to sorbent from 1:1 to 25:1. The design face velocity is 7 feet/minute for the ceramic filter elements. Each of the three vertical cluster assemblies are supported from the high alloy tubesheet and cleaned by a dedicated pulse nozzle. Each cluster has 128 candle filter elements distributed among three plenums vertically arranged in the vessel.

The 384 candle design is similar to the candle system installed at the Tidd facility. Westinghouse has developed the design in over 4,600 hours of operating time under both reducing and oxidizing conditions in various facilities.

Combustor Candle Filter

LLB will provide three 50% ceramic filter assemblies for the PCFB combustor vitiated air. Two units will be kept on-line to clean 815,000 lb/hr of 216 psia/1600°F vitiated air containing fly ash. The design inlet dust loading is 20,000 ppmw, and a conservative face velocity of 5 feet/min has been used for the design basis. Each filter vessel has 1800 candle elements in a 30-feet high x 14-feet diameter refractory-lined pressure vessel with a 17-feet long conical bottom. The LLB design does not have a tubesheet; instead, each of the three levels containing 600 candles has a dedicated manifold comprised of horizontal header tubes and vertical gas collection pipes. Candles are bottom supported instead of the more conventional hanging arrangement.

LLB's design is based on over 3000 hr of operating experience gained at their 15 MWth pilot unit.

Alkali Removal Units

Thermodynamic models indicate that alkali control may be required to protect the gas turbine from erosive alkali sulfate deposits. Westinghouse has developed designs for vertical, downflow beds packed with 1/8" x 1/4" emathlite pellets in a carbon steel, refractory-lined pressure vessel. The beds will be designed for 8000 hours operation. The waste emathlite will be inert, with very low leachability, and can be disposed in a landfill. A single unit will be used to remove approximately 10 ppmv alkali vapor from the carbonizer fuel gas. The PCFB combustor train will require two 50% parallel vessels to remove 0.1 ppmv alkali due to the higher gas flow rate. Future pilot plant tests will determine if the units are required.

Topping Combustor

The topping combustor is supplied by Westinghouse, and is integral to their 251B12 turbine. Its purpose is to increase the inlet temperature to the gas turbine above the 1600°F operating temperature of the PCFB combustor. The low-Btu fuel gas from the carbonizer is burned with vitiated air from the PCFB combustor to generate 213 psia/1975°F gas to the turbine in a steady and controlled manner. There are two critical elements in the topping combustor: the Multi-Annular Swirl Burners (MASB), and the hot valve control system.

Multi-Annular Swirl Burners (MASB)

Combustion of the low-Btu 1400°F fuel gas with 1400°F vitiated air occurs in a ring of eight 18-inch diameter MASBs located in a topping combustor which is external to the combustion turbine. The need to cool the combustor walls with 1400°F air presents a significant challenge. In addition, the fuel gas will contain approximately 0.2 wt% ammonia (NH₃) from the reduction of nitrogen-containing compounds in the coal. The mixing and residence time/temperature distribution in the MASB is critical to minimize NH₃ conversion to NO_x. In addition, thermal NO_x must also be minimized. These constraints preclude the use of conventional combustor designs.

The MASB is a rich-quench-lean combustor based on the design by Dr. Beer [7], with extensive modifications by Westinghouse. It satisfies the demanding requirements by introducing all the combustion air through annuli which have substantial radial thickness. Cooling air is created at the leading edge from each of the concentric inlet sections. Fuel-bound NO_x formation is suppressed by the combustion staging that results from sequencing the air inlets. A high

recirculation rate at the inlet provides flame stability. The design features are discussed in greater detail in Reference [8].

Hot Control Valve System

Because the heating value for carbonizer fuel gas is approximately 130 Btu/scf, its volumetric flow rate is an order of magnitude greater than natural gas. Its high flow rate and 1400°F temperature present challenges for selection of valves to regulate and shut off flow. Unlike a conventional gas turbine, valves are required on the PCFB vitiated air stream for overspeed protection. Merely shutting off the fuel gas system is not sufficient for overspeed protection. The large inventory of hot pressurized air in the PCFB systems and piping contains a considerable amount of thermal energy that must be controlled to prevent the turbine from excessive overspeed. Development of large, high temperature, high pressure valves with quick response for safe shutdown is a challenge that will be addressed in this project.

CURRENT PROJECT STATUS

Since being selected by DOE in May 1993, Air Products and its partners have worked with DOE on its Fact-Finding investigation, Reasonableness Review, and negotiations of a Cooperative Agreement. Following the mandatory 30-day Congressional lay before, the Cooperative Agreement should become effective in early August, 1994. The Cooperative Agreement will be between Four Rivers Energy Partners, a subsidiary of Air Products, and DOE.

Air Products, on behalf of FREP, has also undertaken the development of an Environmental Information Volume (EIV) as part of the DOE's NEPA process. After receiving DOE's response to the draft EIV, a final version was submitted in May, 1994. Based on the attributes of the Four Rivers Project, it is expected that an Environmental Assessment will be the appropriate level of documentation under the National Environmental Policy Act (NEPA) process for the project. DOE anticipates completion of the NEPA process in late 1995.

PROJECT TEAM SCOPE

The project team consists of Air Products, Foster Wheeler, Westinghouse, LLB, and DOE. As the Four Rivers Project team leader, Air Products will provide overall project management, procurement, construction management, and operation services. Air Products will also provide all required non-DOE funding for the project. Following the design and construction phases, Air

Products will operate the plant for 30 months to demonstrate the technology and to develop a database. The plant will then be operated commercially to provide electric power to TVA and steam to Air Products' chemicals manufacturing facility.

Foster Wheeler's effort will be led by Foster Wheeler Energy Corporation, whose scope includes the design, fabrication, and erection of the boiler island. The boiler island includes the carbonizer, PCFB combustor, HRSG, Westinghouse carbonizer filter and alkali removal units, and LLB combustor filter. Foster Wheeler Development Corporation is providing pilot plant tests to support the design. Foster Wheeler USA Corporation will provide the engineering design for the overall plant.

Westinghouse will supply the carbonizer filter and alkali removal units, as well as the design and fabrication of the topping combustor and a modified 251B12 gas turbine.

LLB will provide the PCFB combustor filter, coal slurry feed system and ash removal system. In addition, they will provide engineering services to incorporate their pilot-scale PCFB combustor experience into the Four Rivers design.

DOE will monitor the project activities, give technical advise, assess progress by periodically reviewing the project performance with the other team members, and will participate in the decision making process at major project milestones.

PROJECT SCHEDULE

The Four Rivers project schedule includes the following major milestones with their estimated dates:

- | | |
|-----------------------------------|-----------|
| • Cooperative Agreement Signed | August 94 |
| • Begin Estimating/Engineering | Late 94 |
| • Initiate Procurement Activities | Mid 95 |
| • NEPA/Process Complete | Late 95 |
| • Begin Construction | Early 96 |
| • Begin Commissioning/Start-Up | Mid 98 |
| • Begin Commercial Operations | Late 98 |

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